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DIRECT TESTIMONY OF R. THOMAS BEACH

on behalf of

the Solar Energy Industries Association

Docket No. E-01345A-16-0036

E-01345A-16-0123

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Summary of the Direct Testimony of R. Thomas Beach

This testimony presents the direct testimony of R. Thomas Beach of Crossborder Energy on behalf of the Solar Energy Industries Association (SEIA) in this general rate case (GRC) for Arizona Public Service (APS). This testimony responds and offers alternatives to several of APS's cost-of-service and rate design proposals.

SEIA opposes APS's proposals for mandatory demand charges for many residential and small commercial customers, including APS's proposal that residential customers who install solar distributed generation must take service under a rate design that features a substantial on-peak demand charge. APS justifies this large demand charge based on an assertion that DG customers' rates today fail to come close to covering their cost of service. SEIA's testimony shows that the APS cost-of-service study (COSS) for solar DG customers is flawed, and fails to accurately reflect the costs which such customers impose on the APS system. The APS COSS for DG customers begins with the flawed assumption that APS must continue to serve the full pre-solar site loads of all customers who install DG. This assumes that all of the more than 50,000 solar DG units on the APS system could fail at the same time, which is an absurd assumption. The cost-of-service for DG customers, like the rates for all other customer classes, should be based on the delivered loads which DG customers take from the APS system – in other words, on the service which APS actually provides to solar customers. Rates for DG customers that are set on any other basis may violate the Public Utilities Regulatory Policies Act (PURPA) requirements that the rates for sales to qualifying facilities (QFs) (i.e. DG customers) must not discriminate against such customers and that such rates cannot assume that all QFs will suffer outages at the same time.

Further, a rate design for DG customers that relies on a large demand charge is

neither an accurate nor cost-based means to recover the costs to serve such customers. Only 9% of APS's costs in its own COSS for residential solar customers are driven by customers' individual maximum demands, yet APS would collect 41% of the costs allocated to the proposed R3 rate through the demand charge. Most of APS's costs are driven by customers' loads at the time of system and class peak demands. SEIA shows that the ability of solar customers to reduce these peak demands is captured most accurately in a two-part, time-of-use (TOU) rate design that assigns a significant portion of capacity-related generation, transmission, and distribution costs to a volumetric on-peak rate. APS's present ET-2 rate is an example of such a rate, and this rate should continue to be available to all residential customers, including those who install solar. Because such a rate is cost-based and does not result in a cost shift to other customers, the Commission can eliminate the \$0.70 per kW-month installed capacity charge on solar customers that was implemented in Decision 74202.

Accordingly, a superior, cost-based design for APS's residential rates would be the continued use and promotion of two-part, volumetric time-of-use (TOU) rates. APS also should expand the use of Critical Peak Pricing (CPP) rates, which are very high volumetric rates that are targeted to a defined set of on-peak hours on a limited number of high-demand critical peak days that are called a day in advance. CPP rates accurately target those days when reductions in usage are most valuable, and APS's CPP pilot program has demonstrated load reductions on these critical days that are significantly larger than those produced by TOU or demand-based rates alone.

Experience and customer surveys in Arizona and other states show that residential customers prefer two-part TOU rates and that there are serious customer acceptance issues with demand charges, which require small customers to understand and to track not just when they use energy, but also the rate at which they do so over small time

increments. As a result of such concerns, no other state regulatory agency has imposed mandatory demand charges on residential customers, and this Commission should not do so in this case.

SEIA's testimony reviews how APS's costs for generation, transmission, and primary distribution vary over the course of the day. This review indicates that the appropriate on-peak period for APS is 2 p.m. to 7 p.m., one hour earlier than the utility has proposed. Our review considers the time dependence of more cost components than APS's witness reviewed. We also believe that customers are more likely to accept a more gradual approach to shifting TOU periods than what APS has proposed.

SEIA opposes APS's proposal to increase to \$24 per month the monthly fixed charge applicable to residential DG customers. The proposed fixed charge includes costs that are not independent of a customer's usage, such as the costs for transformers that can serve many customers and for grid operations that are not simply a function of the number of customers.

This testimony reviews the impacts which the APS rate design proposals would have on the DG market in Arizona. APS is proposing a rate design similar to the demand-charge-based rate design adopted in 2015 by the Salt River Project (SRP), a rate design that decimated the solar DG market in SRP's service territory. The only aspect of APS's rates for solar customers that is more favorable than what SRP implemented is the new rate for exported power adopted in December 2016 in Decision 75859. However, that order provides that the APS export rate may decline quickly in coming years. SEIA's calculations are that APS's rate design proposals will result in a reduction of more than 40% in solar customers' bill savings from serving onsite loads. A similar reduction in bill savings in Nevada in 2015 (which has now been reversed for one

Nevada utility) had a devastating impact on the solar market in that state. The Commission should review carefully the cumulative impact on the solar DG market in the APS service territory of both the changes to the solar DG export rate in Decision 75859 and the rate design changes that are proposed in this case.

Finally, SEIA comments on the APS Solar Partners Program, whereby APS has leased the roof space of about 1,600 customers in order to install utility-owned solar DG systems that provide power to the utility on its side of the meter and that include advanced inverters and communications capabilities. SEIA supports the research goals of this program (and APS's recovery of the program's costs), provided the utility makes public what it learns from this program, including the detailed impacts of these DG installations on the APS distribution system. That said, if in the future this program were to be expanded, SEIA would have concerns that its structure could be discriminatory and anti-competitive, compared to the much different treatment of customer-owned or third party-owned solar DG in APS's service territory.

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Direct Testimony of R. Thomas Beach
on behalf of the Solar Energy Industries Association
Docket No. E-01345A-16-0036

1 I. INTRODUCTION AND QUALIFICATIONS

2
3 **Q1: Please state for the record your name, position, and business address.**

4 A1: My name is R. Thomas Beach. I am principal consultant of the consulting firm
5 Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley,
6 California 94710.

7
8 **Q2: Please describe your experience and qualifications.**

9 A2: My experience and qualifications are described in the attached *curriculum vitae* (CV),
10 which is Exhibit RTB-1 to this testimony. As reflected in my CV, I have more than 35
11 years of experience on rate design and ratemaking issues for natural gas and electric
12 utilities. I graduated from Dartmouth College in 1977 with a B.A. in English and
13 physics. In 1980, I completed an M.E. degree in mechanical engineering from the
14 University of California at Berkeley. I am a registered professional engineer in the state
15 of California. I began my career in 1981 on the staff at the California Public Utilities
16 Commission (CPUC), working on the implementation of the Public Utility Regulatory
17 Policies Act (PURPA). From 1984-1989, I was an advisor to three CPUC
18 commissioners. Since 1989, I have had a private consulting practice on energy issues and
19 have appeared, testified, or submitted testimony, studies, or reports on numerous
20 occasions before state regulatory commissions in Arizona and nineteen other states. My
21 CV includes a list of the formal testimony that I have sponsored in various state
22 regulatory proceedings concerning electric and gas utilities.

23
24 **Q3: Please describe more specifically your experience on rate design and the rates**
25 **applicable to renewable distributed generation (DG) resources.**

26 A3: Over the last decade, I have sponsored testimony on rate design issues concerning solar
27 DG in Arizona, California, Colorado, Idaho, Massachusetts, New Hampshire, Nevada,

1 and Texas. This includes representing several solar industry groups in the CPUC's major
2 investigation from 2012-2015 into residential rate design in California. In 2014-2015, I
3 participated in the Hawaii Public Utilities Commission's investigation into distributed
4 generation and net energy metering (NEM) by designing a new residential time-of-use
5 (TOU) rate for the Hawaiian investor-owned utilities. With respect to benefit-cost issues
6 concerning renewable DG, I have sponsored testimony on NEM and solar economics in
7 Arizona, California, Colorado, Idaho, Minnesota, Nevada, New Hampshire, New
8 Mexico, North Carolina, South Carolina, Texas, and Virginia. I also co-authored the
9 chapter on Distributed Generation Policy in *America's Power Plan*, a report on emerging
10 energy issues, which was released in 2013 and is designed to provide policymakers with
11 tools (including rate design changes) to address key questions concerning distributed
12 generation resources.¹ In the last four years, I have co-authored benefit-cost studies of
13 NEM or solar DG in Arizona, California, Colorado, New Hampshire, and North Carolina,
14 including benefit-cost studies of solar DG on the Arizona Public Service (APS) system in
15 2013 and 2016.²

16
17 **Q4: Have you testified or appeared previously before this Commission?**

18 A4: Yes, I have. I sponsored testimony on behalf of The Alliance for Solar Choice (TASC)
19 in the Value of Solar Docket No. E-00000J-14-0023. I also testified on behalf of the
20 Energy Freedom Coalition of America (EFCA) in Tucson Electric Power's Renewable
21 Energy Standard and Tariff (REST) proceeding, Docket No. E-01933A-15-0239.

22
23 **Q5: On whose behalf are you testifying today?**

24 A5: I am appearing on behalf of SEIA. SEIA is the national trade association of the United
25 States solar industry. Through advocacy and education, SEIA and its 1,000 member
26 companies work to make solar energy a mainstream and significant energy source by

¹ This report has been published in *The Electricity Journal*, Volume 26, Issue 8 (October 2013). It is also available at <http://americaspowerplan.com/>.

² The Arizona studies are *The Benefits and Costs of Solar Distributed Generation for Arizona Public Service* (May 2013), available at <http://www.seia.org/sites/default/files/resources/AZ-Distributed-Generation.pdf>, and the update to this study from February 2016 which is in the record of the Value of Solar Docket No. E-00000J-14-0023, submitted as an exhibit to my testimony in that case on behalf of The Alliance for Solar Choice.

expanding markets, removing market barriers, strengthening the industry, and educating the public on the benefits of solar energy. SEIA's members have a strong interest in the adoption and implementation of innovative, forward-looking policies and programs that will accelerate the development of solar photovoltaic (PV) generation. The views contained in this testimony represent the position of SEIA as an organization, but not necessarily the views of any particular member with respect to any issue.

II. BACKGROUND

A. APS's Rate Design Proposals

Q6: Please describe the APS rate design proposals that are of principal concern to SEIA.

A6: SEIA's primary concern is APS's proposal to make three-part rates, including an on-peak demand charge, mandatory for all residential customers, including those who install solar DG, except for the smallest customers who use less than 600 kWh per month. APS proposes to require residential customers to choose one of three rates (R1, R2, and R3), all of which have significant levels of on-peak demand charges. The on-peak demand charges would be based on a customer's maximum hourly usage in each monthly billing period during a new 3 p.m. to 8 p.m. on-peak period. APS's proposed R1, R2, and R3 rates are shown in **Table 1** below.

Table 1: APS's Proposed Three-part Residential Rates

Rate Schedule	Season	Monthly Charge \$/Month	On-Peak Energy \$/kWh	Off-Peak Energy \$/kWh	Summer On-Peak Demand \$/kW	Winter On-peak Demand \$/kW
R1	Summer	24.00	0.15160	0.15160	6.60	6.60
	Winter		0.08070	0.08070		
R2	Summer	14.50	0.12730	0.12730	8.40	8.40
	Winter		0.08070	0.08070		
R3	Summer	24.00	0.09090	0.06670	16.40	11.50
	Winter		0.05475	0.05475		

Q7: Does APS propose to limit the rate options available to new solar DG customers?

1 A7: Yes. New solar customers would be required to take service on the R3 rate that has the
2 highest basic service charge, the largest demand charge, and the lowest volumetric TOU
3 rates.³ My testimony addresses the negative impact that this rate proposal would have on
4 the solar market in Arizona. APS claims that this restriction is necessary because solar
5 customers currently pay rates that cover a much smaller percentage of their cost of
6 service than other residential customers. For example, APS claims, as justification, that
7 its cost-of-service study (COSS) shows that solar customers pay just 38% of the costs
8 they impose, compared to 88% for regular residential customers.⁴ However, the utility's
9 COSS study is flawed, APS's proposed demand charges are excessive for residential
10 customers, and there is no justification for imposing the R3 rate on all new solar
11 customers. My testimony explains why demand charges are not as accurate or cost-based
12 as targeted volumetric TOU rates, which are a superior rate design to APS's proposal.
13

14 **Q8: What are the principal reasons that APS cites as justification for this new**
15 **residential rate design?**

16 A8: APS argues that customers who have access today to a variety of demand-side energy
17 technologies should face three-part rates that allegedly are more accurate because they
18 include a demand charge that covers a portion of the utility's costs that are classified as
19 demand-related. APS believes that three-part rates are better aligned with their costs,
20 send more accurate price signals, and thus are more equitable for all ratepayers.⁵ As
21 explained below, I disagree with these conclusions and note that no other state has
22 adopted mandatory residential demand charges.
23

24 **Q9: Has APS made any other rate design proposals related to solar customers?**

25 A9: Yes. The utility has placed solar customers in their own sub-class for allocation
26 purposes, although APS has not proposed different rates for solar customers than for
27 other residential ratepayers. In addition, APS proposed a new, lower rate for solar
28 customers' exports to the grid,⁶ although this proposal has been superseded by the

³ APS Direct Testimony (Miessner), at p. 4 and 24-25; also APS (Snook), at pp. 31-32.

⁴ APS Direct Testimony (Miessner), at p. 44; also APS (Snook), at pp. 28-30.

⁵ APS Direct Testimony (Miessner), at pp. 6-9.

⁶ *Ibid.*, at p. 45.

1 methodology for determining export rates that the Commission adopted in Decision
2 75859 in the "Value of Solar" Docket No. E-00000J-14-0023.

3
4 **B. Impacts of Decision 75859**

5
6 **Q10: Please explain the principal impacts on this APS GRC of the Commission's recent**
7 **Decision 75859 in the "Value of Solar" Docket No. E-00000J-14-0023.**

8 A10: This order decided to no longer provide new solar customers in Arizona with net
9 metering, whereby exported power is compensated at the full volumetric rate, and to end
10 the ability of new solar customers to "bank" or carry forward kWh credits from NEM
11 exports to subsequent months. Instead, the Commission determined that the rate for
12 power exported by new solar customers will be set under one of two different
13 methodologies, with the choice between the two methods (and the details of the adopted
14 method) to be determined in subsequent rate cases. Finally, as noted above, the
15 Commission stated that customers who install DG are partial requirements customers
16 who export power to the grid, and for this reason "rooftop solar customers are a separate
17 class of customers," and should be so treated in rate cases such as this one.⁷

18
19 **C. Ratemaking principles**

20
21 **Q11: Is there a widely-cited academic text that sets forth the principles of utility rate**
22 **design that many regulators have relied on over the years?**

23 A11: Yes. For example, a commonly-cited list of the goals for utility rate design is set forth in
24 Professor James Bonbright's *Principles of Public Utility Rates*.⁸ The Bonbright
25 principles enumerate eight central qualities of a just and reasonable rate structure:

- 26 1. The related, "practical" attributes of simplicity, understandability, public
27 acceptability, and feasibility of application.
- 28
- 29 2. Freedom from controversies as to proper interpretation.
- 30

⁷ See Decision 75859 at p. 146.

⁸ James Bonbright, *Principles of Public Utility Rates*, 291 Columbia University Press (1961).

- 1 3. Effectiveness in yielding total revenue requirements under the fair-return
2 standard.
- 3
- 4 4. Revenue stability from year to year.
- 5
- 6 5. Stability of the rates themselves, with a minimum of unexpected changes
7 seriously adverse to existing customers.
- 8
- 9 6. Fairness of the specific rates in the appointment of total costs of service among
10 the different customers.
- 11
- 12 7. Avoidance of "undue discrimination" in rate relationships.
- 13
- 14 8. Static efficiency of the rate classes and rate blocks in discouraging wasteful use of
15 service.
- 16
- 17 9. Dynamic efficiency in promoting innovation and responding economically to
18 changing demand and supply patterns.
- 19
- 20 10. Reflection of all of the present and future private and social costs and benefits
21 occasioned by a service's provision (i.e., all internalities and externalities).
- 22

23 The sixth Bonbright principle of "fairness of the specific rates in the appointment of total
24 costs of service among the different consumers" generally is taken to mean that rates
25 should be based on the costs which customers cause the utility to incur. Generally, I
26 agree that the Bonbright principles include many of the goals that utility regulators often
27 consider in setting rates. I would observe, however, that regulators do not always place
28 equal emphasis on all of the Bonbright principles, and that the principles which are
29 emphasized most heavily can change over time as states' policy priorities evolve with the
30 circumstances they face. For example, today's imperative to move to an electric system
31 with cleaner and more sustainable forms of generation argues for increased emphasis on
32 Principle No. 10 – "reflection of all of the present and future private and social costs and
33 benefits occasioned by a service's provision (i.e., all internalities and externalities)."
34 Today's increasing ability and interest of customers in producing their own electricity
35 and in choosing how and when to consume it places more emphasis on Principles No. 8
36 and 9, the efficiency of rates in allowing customers to eliminate wasteful use and to
37 respond economically to changing demand and supply patterns. Furthermore, at times
38 when rate design is changing, Bonbright's "practical" Principles Nos. 1 and 2 of

1 simplicity, understandability, public acceptability, and freedom from controversy over
2 implementation will assume greater importance, as regulators seek assurance that
3 customers understand and accept new rate structures.
4

5 **III. APS'S PROPOSED DEMAND CHARGE-BASED RATE IS EXCESSIVE FOR**
6 **RESIDENTIAL AND SMALL COMMERCIAL CUSTOMERS WHO INSTALL DG.**
7
8

9 **A. The APS Cost of Service Study for DG Customers Is Flawed.**
10

11 **Q12: Have you reviewed the APS Cost of Service Study (COSS) for residential and small**
12 **commercial DG customers?**

13 A12: Yes, I have. I will discuss below a number of conceptual flaws in the APS COSS's
14 treatment of DG customers:

- 15
- 16 • The costs to serve solar DG customers should not be based on their total site
- 17 loads, but on the loads that APS delivers to them.
- 18
- 19 • The noncoincident class peaks (NCPs) for solar DG customers should be assessed
- 20 not at the time of the solar subclass's peak, but instead at the time of the entire
- 21 residential class's peak.
- 22
- 23 • New solar customers should not be assessed for the costs of a second production
- 24 meter that does not benefit them.
- 25

26 I understand that Ms. Briana Kobor for Vote Solar will be presenting an analysis of the
27 costs to serve solar customers which corrects these deficiencies in the APS COSS.
28

29 **Q13: Please explain how a residential customer's installation of solar DG will impact**
30 **APS's cost to serve that customer.**

31 A13: When a residential customer installs solar, a significant share of the solar output will
32 serve the customer's on-site load directly, without ever touching the grid. The share of
33 solar output which serves the on-site load is typically at least 40%, and for some
34 customers more than 50%, depending on system size, the customer's load profile, and the

1 metering interval.⁹ This portion of solar output will reduce directly the power that APS
2 must deliver to the customer, so the customer's delivered load from the APS system will
3 be significantly smaller than the customer's total site load. Reducing the amount of
4 power that APS must deliver to the DG customer will reduce APS's costs to provide
5 service to the DG customer. APS's cost of service for solar customers thus should be
6 based directly on the delivered loads of those customers, which is the correct measure of
7 the service that APS is providing to them.

8
9 The remainder of the solar output – the output in excess of the customer's
10 immediate on-site load – will be exported to the grid. These exports are a service which
11 the DG customer provides to the APS system, as another source of generation which APS
12 then uses to serve other customers on its system. In Decision 75859, the Commission
13 established a new approach to compensating new DG customers for these exports, which
14 SEIA will address in further testimony scheduled in this docket. In accordance with that
15 decision, the value of exported generation¹⁰ should not be included in the COSS, which
16 should be based on APS's cost of providing service to solar customers.

17
18 **Q14: Does APS agree that a DG customer's rate should be based only on the delivered**
19 **loads which are the service that the solar customer takes from the APS system?**

20 A14: Not directly. APS's cost of service analysis begins with the DG customer's total site
21 load, and then the utility credits the DG customer for "the value of the energy and
22 capacity that they supply from their own rooftop solar system."¹⁰ APS witness Snook
23 summarizes these credits on page 25 of his direct testimony. Most of these credits appear
24 to be based on the cost of service difference between total site load and delivered load, so
25 the net result appears to be that APS is assuming that the customer's delivered load
26 should be the basis for the costs to serve DG customers.¹¹ In fact, Mr. Snook concludes

⁹ The data from APS's 2015 census of solar customers shows that 44% of the average solar customer's production in 2015 served their on-site load, with 56% exported to the grid. The percentage of exports for APS is larger than for other utilities because APS uses two-channel meters that instantaneously measure exports and imports.

¹⁰ APS Direct Testimony (Snook), at p. 26.

¹¹ For example, APS states that it develops credits for production capacity, transmission, and distribution costs based on "a comparison to the APS-delivered customer load." *Ibid.*, at p. 25.

1 that "[t]he result is that the COSS analysis only allocates capacity and energy costs to
2 NEM customers based on what APS has to provide."¹²

3
4 Nonetheless, I disagree fundamentally with the APS argument that it is reasonable
5 to start with a DG customer's total load because, in Mr. Snook's words, "APS continues
6 to supply a host of back-up and ancillary services that in turn require APS to build,
7 operate and maintain the bulk of its fixed infrastructure required to serve that NEM
8 customer."¹³ APS must provide exactly the same services to meet unexpected
9 fluctuations in the loads of non-DG customers, which also are variable. For non-DG
10 customers, APS calculates rates and recovers the costs for all of these services based only
11 on delivered loads. APS does not charge non-DG customers an extra amount even
12 though there is the real possibility that their usage might increase unexpectedly.
13 Moreover, the starting premise that APS might have to serve the full site loads of all DG
14 customers is completely unrealistic, because solar DG systems are very reliable and,
15 moreover, the tens of thousands of DG systems in the APS territory will not all fail at the
16 same time.

17
18 As a result, DG customers' cost-of-service should be based entirely and directly
19 on their delivered loads, without APS's complex, atypical, and unnecessary crediting
20 mechanism. Delivered loads are exactly the service which the utility provides to DG
21 customers. Decision 75859 has specified how to price exported power based on the value
22 of solar. What remains to be priced in this case is just solar customers' delivered loads.

23
24 **Q15: Are there flaws in how APS has determined the credits to residential DG customers**
25 **for certain cost elements?**

26 A15: Yes. First, on the cost side, APS's COSS departs from an analysis of delivered loads by
27 assigning the embedded cost energy value to the entire output of DG customers,
28 including exports. This valuation for exports is inconsistent with the approach adopted
29 for valuing exports in Decision 75859, and significantly distorts APS's cost of service

¹² *Ibid.*, at p. 25.

¹³ *Ibid.*, at p. 26.

1 analysis by underestimating the value of exports. Further, on the revenue side, APS
2 calculates the revenues from DG customers assuming compensation for exports at the full
3 retail rate, which Decision 75859 has now changed. This underestimates the revenues
4 from DG customers. As noted above, the correct approach is to remove exports from
5 both the cost and revenue calculations, and to focus on the cost of service only for the
6 delivered loads of solar customers.

7
8 **Q16: What other flaws in the COSS have you identified?**

9 A16: The second major flaw is that APS's credits for primary and substation distribution costs
10 are based on comparing total site load to delivered load at the time of the four summer
11 sub-class noncoincident class peaks (NCPs). The sub-class for solar DG customers
12 includes only solar customers. However, substations and the primary distribution system
13 do not just serve DG customers; instead, they serve aggregated loads that include all of
14 the residential sub-classes, including both non-DG and DG sub-classes. In other words, a
15 primary distribution circuit serving residential load will serve a mix of residential
16 customers, including both non-DG and DG customers. Thus, APS's distribution costs are
17 driven by the peak load of the entire residential class, not by the peak of a specific sub-
18 class.¹⁴ Accordingly, the primary distribution costs to serve DG customers should be
19 based on their delivered load at the time of the full residential class's NCP. APS's
20 analysis erroneously assumes, in effect, that all solar customers are clustered together on
21 circuits that only serve solar customers. This simply does not reflect reality, and results
22 in overstating solar customer's NCP demands that drive distribution costs.

23
24 **Q17: Are there any other problematic aspects of APS's cost allocation to solar customers?**

25 A17: Yes. The metering costs allocated to residential solar customers are significantly higher
26 than those allocated to other residential customers. This appears to be due principally to
27 including the costs of a second meter to measure solar production as well as a regular
28 meter that measures imported and exported power.

¹⁴ It is conservative to assume that residential distribution costs are driven by residential loads at the time of the class peak, because many distribution circuits and substations that serve predominantly residential customers also will serve some commercial loads that tend to peak earlier in the day.

1
2 **Q18: Why do APS's solar customers have a second production meter?**

3 A18: APS's solar incentive programs originally required a second meter, so that APS could be
4 credited with the renewable energy credits (RECs) from solar DG. This allowed the APS
5 service territory to comply with the DG set-aside requirements of the Renewable Energy
6 Standard Tariff (REST). In this way, the general body of APS ratepayers benefitted from
7 the second meter, as a means to verify the benefits of an increasing penetration of clean
8 energy resources. The second meter also was intended to monitor the output of systems
9 that received incentives.¹⁵
10

11 **Q19: Going forward, will new solar DG customers benefit from the second production**
12 **meter?**

13 A19: No, they will not, unless they have some need to track the RECs from their systems. The
14 APS solar incentive programs have now terminated; nonetheless, the requirement for a
15 second production meter remains and APS continues to use the data from those meters to
16 demonstrate compliance with the REST DG set-aside.¹⁶ There might be some
17 justification for solar customers bearing a portion of the cost of the second meter if, for
18 example, they could benefit from the sale of their RECs to APS or other utilities for
19 REST compliance. However, to my knowledge, there is no such viable REC market in
20 Arizona, as the Commission has found the utilities to be in compliance with the REST
21 DG set-aside without actually having to purchase RECs from customers. Thus, it is not
22 surprising that RECs from solar DG have no value in Arizona.
23

24 **Q20: Is there a need for a second production meter to develop a cost allocation and rate**
25 **design for DG customers?**

¹⁵ See Decision 72737, at pages 8-9.

¹⁶ See, generally, Decision 74882 and APS REST filings that cite production data from unsubsidized DG systems to justify waivers from the REST DG requirements. For example, see the APS 2017-2021 REST Plan filed July 1, 2016 in Docket No. E-01345A-16-0238, at pp. 2-4 requesting a permanent waiver from the REST DG requirement and Exhibits 2B and 2C of the attached REST Plan, showing production from both incentivized and non-incentivized DG systems.

1 A20: No, there is not. As discussed above, costs should be allocated to DG customers based
2 solely on their delivered loads from APS. This is what is measured by the standard
3 meter. The standard meter also measures exports to APS. Thus, there is no need for the
4 data from a production meter to develop APS's cost allocation or rate design.
5

6 **Q21: Are there potentially other benefits to APS and its ratepayers from the second**
7 **production meter?**

8 A21: Yes. APS can use the data from production meters to have visibility into the total site
9 loads on its system and the total output of DG solar. This visibility may become more
10 important operationally and for planning purposes as DG penetration increases. This data
11 will benefit all APS customers as the utility relies more heavily on customer-sited
12 distributed energy resources of many types (for example, on-site storage and demand
13 response resources as well as solar DG) to serve the overall loads on its system.¹⁷
14

15 **Q22: Does SEIA recommend removing the requirement for a second production meter?**

16 A22: Yes. If a customer wishes to have a second production meter to track and retire their
17 RECs, the costs for the second meter should be split 50/50 with APS, as APS also will
18 benefit from the meter, as described above.
19

20 **Q23: If the requirement for a second production meter continues, or if APS chooses to**
21 **install production meters on certain solar customers, how should the costs be**
22 **allocated?**

23 A23: The costs should be allocated to all ratepayers, given the benefits to all ratepayers from
24 REST compliance and from visibility into the output of DG on the APS system.
25

26 **Q24: Will the record include a cost of service analysis for APS that corrects these**
27 **problems?**

¹⁷ APS's 2017 Preliminary IRP, filed September 30, 2016 in Docket E-0000V-15-0094, at Table 3, shows that over the five years from 2017-2021 APS expects to rely on customer-sited resources (solar DG, energy efficiency, demand response, and microgrids) for about one-quarter of its resource additions. This assumes a relatively low capacity contribution from solar DG, which could be significantly higher with policies to encourage west-facing systems or the addition of storage.

1 A24: Yes. It is my understanding that Ms. Kobor for Vote Solar is presenting an analysis that
2 updates the cost of service for APS's residential solar customers based on the three
3 significant changes to the APS COSS model that I have described above:

- 4 1. Using the delivered loads of solar DG customers (i.e. based on the actual service
5 that DG customers take from APS),
- 6 2. Calculating solar customers' costs that are based on the noncoincident class peak
7 (NCP) using the full residential class peaks rather than the solar sub-class peaks
8 (i.e. recognizing that the APS distribution system serves a mix of solar and non-
9 solar customers), and
- 10 3. Removing the cost for the second production meter from solar customers' cost of
11 service.

12
13 **Q25: Does APS calculate the cost of service for small commercial DG customers in the**
14 **same way that it does for residential DG customers?**

15 A25: No, it does not. First, APS does not place commercial solar customers into a separate
16 sub-class for cost allocation. This is also contrary to Decision 75859, which directed that
17 DG customers should be placed into a separate class because of their status as partial
18 requirements customers. Small commercial customers who install DG are just as much
19 partial requirements customers as residential DG customers. Second, APS does not start
20 the analysis of the cost-of-service for commercial solar customers with their total site
21 loads. Instead, APS looks only at the delivered loads of commercial solar customers, and
22 does not have complete hourly data on the total site loads for many of these customers.¹⁸
23

24 **B. Demand Charges Are Not As Accurate or Cost-based As TOU Rates.**
25

26 **Q26: APS proposes that residential customers who install DG must take service under its**
27 **proposed R3 rate which includes a large demand charge based on a customer's**
28 **maximum hourly on-peak demand during the billing period. Please explain**
29 **generally why a rate design based on such a large demand charge is not cost-based**
30 **for residential customers who install DG.**

¹⁸ See APS response to SEIA Data Request 3.1, included in **Attachment RTB-3**.

1 A26: Demand charges based on an individual residential customer's maximum demand fail to
2 consider the diversity of such customers' loads. There is significant load diversity,
3 particularly on the upstream portions of the system – e.g. at the generation level, on the
4 transmission system, at distribution substations, and on higher-voltage primary
5 distribution circuits. Where there is significant diversity, the utility serves the aggregate,
6 diversified demand during peak periods, not the sum of individual customers' maximum
7 demand. On the distribution system, this is particularly true on the distribution facilities
8 that serve residential loads. There is a level of diversity on residential distribution
9 systems with many small customers such that the utility does not have to plan to size
10 residential circuits or substations to serve the sum of the individual, non-coincident
11 demands of all residential customers in the area. Such diversity does not exist to the
12 same extent on circuits serving large customers, and thus non-coincident demand charges
13 based on individual customer's maximum demands are more reasonably a part of large
14 commercial and industrial distribution rates.
15

16 **Q27: In fact, doesn't APS's COSS assume that only a small portion of its residential cost-**
17 **of-service are driven by the sum of individual customers' maximum demands?**

18 A27: That's correct. APS allocates only the portion of the distribution system closest to the
19 customer – the secondary system, transformers, and services – based on the sum of
20 customers' individual maximum demands. This is the portion of the distribution system
21 that has the least diversity and that is impacted most strongly by individual customers'
22 maximum demands. However, this portion of distribution costs amounts to just 7% of
23 residential class costs and 9% of residential solar sub-class costs. Yet APS would require
24 residential solar customers to pay an R3 rate that recovers 41% of class revenues using a
25 demand charge based on customer's maximum on-peak demand.¹⁹ Thus, the R3 rate is
26 inaccurate and not cost-based because it fails to match how costs are incurred with how
27 they are recovered in rates.
28

¹⁹ See "CAM_WP01DR – Proof of Revenue.xlsx" workpaper, "R-3 Proposed" tab.

1 **Q28: If it is it unfair and inefficient to base a large portion of a customer's rate on a**
2 **demand charge driven by the customer's individual maximum demand, what better**
3 **metric of the customer's usage should be used?**

4 A28: Due to the diversity of small customers' loads, a customer's average demand (i.e. its
5 volumetric usage) during a peak TOU period is a better measure of a customer's
6 contribution to the costs of the upstream portions of the electric system than the
7 customer's maximum 60-minute demand. This is particularly true for solar DG
8 customers, whose individual maximum demand is likely to occur at times of lower
9 system demand, either in the evening or on cooler, cloudy days.²⁰ As a result, it is
10 reasonable to collect capacity-related costs from residential customers based on their
11 average demand over a summer on-peak TOU period that covers just the hours when both
12 the overall system and substations/circuits on the transmission and distribution (T&D)
13 systems are most likely to peak. This can be accomplished through a volumetric TOU
14 rate that focuses the recovery of capacity-related costs during these peak hours, such as
15 APS's existing ET-2 rate. A customer's kWh usage over the peak period measures the
16 customer's contribution to the average, diversified demand during those hours and is a
17 reasonable, cost-based charge.

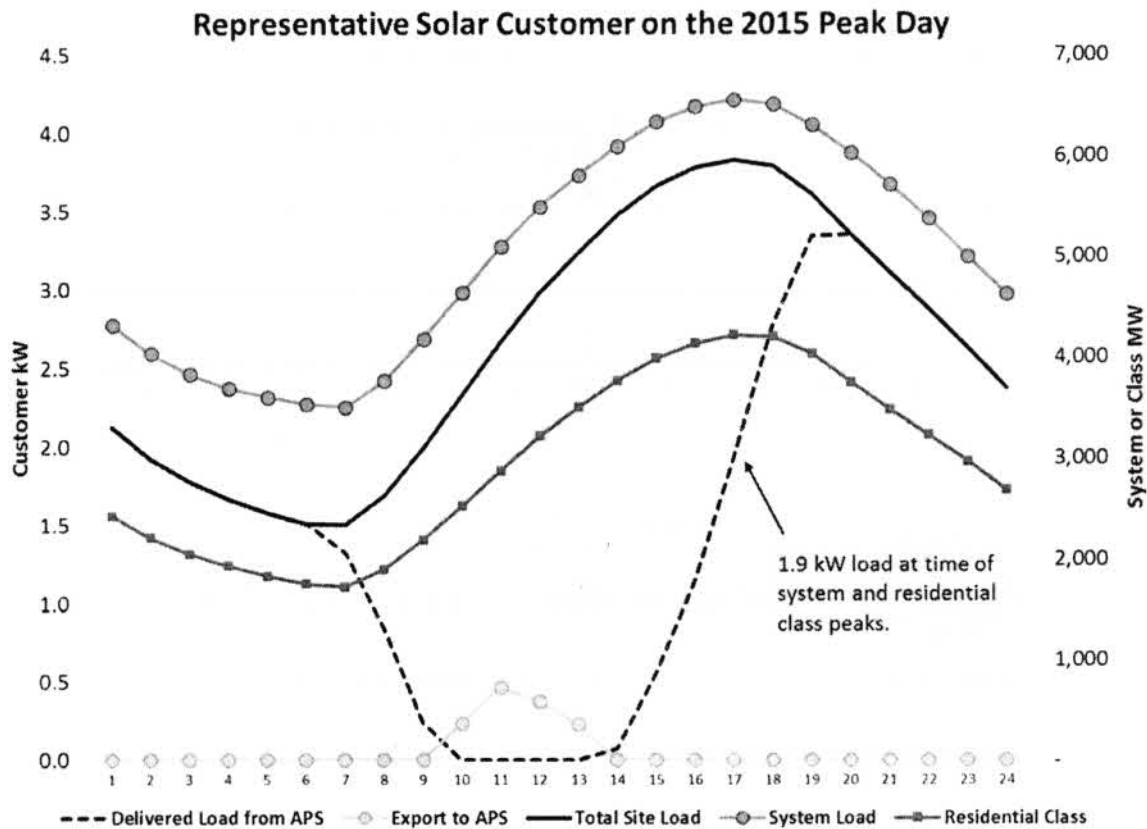
18
19 An even more accurate rate design is to use a very high Critical Peak Pricing
20 (CPP) rate on the days of highest demand. A CPP rate is a volumetric TOU rate that
21 charges a very high on-peak rate to customers in a limited number of high-demand hours
22 each year that the utility or system operator declare on a day-ahead basis. TOU and CPP
23 rates represent a more accurate, targeted, and cost-based means to charge customers than
24 the traditional 15- or 60-minute maximum demand charge.

25
26 **Q29: Can you provide a simple example of why a customer's volumetric usage during a**
27 **peak TOU period is a better measure of a customer's contribution to these costs**
28 **than the customer's maximum 60-minute on-peak demand?**

²⁰ See CPUC Decision No. 14-12-080 (December 18, 2014), finding that the rate design for commercial solar customers should include reduced demand charges, for this reason. See <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K631/143631744.PDF>.

A29: Yes. **Figure 1** illustrates this point graphically. The figure shows the site loads (black solid line), delivered loads (black dashes), and exported generation (yellow) for an exemplary residential solar customer on APS's system peak day in 2015 (August 15). The figure also shows APS's system (green) and residential class loads (blue) on that peak day, using the MW scale on the right side of the chart.

Figure 1



On this peak day, both the coincident system peak (CP) and the residential noncoincident class peak (NCP) occurred in Hour Ending 17 (4 p.m. to 5 p.m.). Based on the APS COSS, residential demand during this hour drove APS's generation, transmission, and distribution demand costs. In this hour, the customer's delivered load was 1.9 kW, a reduction of 50% from the total site load (i.e. the pre-solar load) at that time (3.8 kW). This means that the customer's installation of solar reduced the customer's contribution to APS's demand-related costs by 50%. If this customer were charged such demand-related costs based on a maximum on-peak (3 p.m. to 8 p.m.)

1 demand charge, the customer would have to pay based on its 3.4 kW load in the hour
2 from 7 p.m. to 8 p.m., which does not coincide with the CP or NCP and is just 10% lower
3 than the customer's maximum load in the absence of solar. This means that the
4 customer's payment for demand-related costs would drop by only 10% despite the
5 customer having reduced its contribution toward those costs by 50%. It would be far
6 more accurate and cost-based for this customer to pay a rate based on its volumetric load
7 over a 2 p.m. to 7 p.m. peak period, which averaged 2.0 kW, close to the customer's CP
8 and NCP load of 1.9 kW. Thus, the customer's average demand (i.e. its volumetric
9 usage) over the peak period is the most accurate measure of the customer's contribution
10 to demand-related costs. This example obviously shows just a single day, while the
11 customer's bill is based on usage over a monthly billing period, but the example is
12 illustrative of costs incurred over the billing period, and it depicts a consequential, high-
13 demand day (the 2015 system peak day).

14
15 **Q30: Based on your analysis of the APS cost of service study and the 2015 data on solar**
16 **customer usage, by how much does an average residential customer reduce APS's**
17 **cost of service when the customer adds solar?**

18 A30: This calculation is shown in **Tables 2 and 3** below, based on an analysis we conducted of
19 the total on-site and delivered loads of the 2015 census of residential solar DG
20 customers.²¹ When a customer adds solar, APS then serves the delivered loads of such
21 customers, not the total site load. **Table 2** shows the change in the key APS cost metrics
22 as a result of adding solar. Not that I have assessed the four summer NCP costs for solar
23 customers based on their usage at the time of the residential class peak, for the reasons
24 explained above.

25 //

²¹ This analysis uses the 2015 census data for all solar customers with a complete 12 months of hourly billing data.

Table 2: Change in Key Cost Metrics from Residential Customers Adding Solar (kW)

Cost Metric	Solar Customers on Energy-based Rates (25,837 customers)			Solar Customers on Demand-based Rates (919 customers)			Weighted Average
	Pre Solar (kW)	Post Solar (kW)	Percent Change	Pre Solar (kW)	Post Solar (kW)	Percent Change	Percent Change
Annual Energy (Average kW)	1.9	1.3	-31%	3.2	2.4	-26%	-30%
System Peak (4 CP)	4.9	2.8	-43%	7.2	4.7	-35%	-42%
Residential Class Peak (4 NCP)	4.9	3.3	-34%	7.5	5.4	-27%	-33%
Sum of Individual Max Demands	6.9	6.2	-10.0%	9.5	8.7	-7.6%	-10%

Table 3 uses the results from Table 2 to calculate the percentage reduction in each component of APS's cost of service that results from a residential customer's addition of a solar system. The overall percentage reduction in costs is the weighted average change across all cost components, with the weighting based on each component's average functionalized cost for the APS system in the 2015 test year.

Table 3: Change in APS Residential Costs due to Solar

Cost Component	Basis for Cost Allocation	Average Cost (\$/MWh)	Reduction due to Solar (%)
Energy	Annual Energy	\$33.57	-30%
Production Demand	4CP / 4 NCP	\$37.26	-38%
Transmission	4CP	\$8.50	-42%
Distribution – Primary & Substations	4 NCP	\$14.51	-33%
Distribution – Secondary	Sum of Individual Max Demands	\$7.60	-10%
All Categories (Weighted by Average Cost)		\$101.44	-33%

Thus, the addition of solar should result, for the average solar customer, in a 33% reduction in APS's cost of providing service to that customer for the cost elements shown in Table 3. Rates for solar customers that are designed to achieve this will be cost-based, and will not shift costs to other customers.

1 **Q31: Mr. Snook cites calculations of percentage reductions in cost-of-service components**
2 **from adding solar on page 27 of his direct testimony; some of his percentage**
3 **reductions are much lower than those shown in Table 3, esp. for Production**
4 **Demand and Distribution – Primary & Substation. What do you believe accounts**
5 **for the difference?**

6 A31: The major difference is that I have assessed the difference in four summer NCPs at the
7 time of the residential class peak, instead of at the time of the solar sub-class peak. As
8 discussed above, this correctly reflects the fact that residential distribution circuits serve a
9 mix of standard and DG customers, and thus it is the overall residential NCP that drives
10 production demand and primary distribution costs for all sub-classes of residential
11 customers.

12
13 **Q32: Why does your analysis show that a three-part rate with a large demand charge will**
14 **not be cost-based?**

15 A32: A rate based largely on an on-peak demand charge cannot accurately reflect a solar
16 customer's cost of service if the proposed tariff, like APS's proposed R3 tariff, collects
17 41% of revenues through the demand charge, because individual peak demand only
18 drives 9% of customers' costs. Further, by going solar, the customer will only be able to
19 reduce the demand charge portion of the rate by 10%, as shown in Table 3. Thus, to
20 achieve an overall, cost-based 33% reduction in costs when a customer adds solar, the
21 rate design for solar customers cannot rely on fixed or demand charges to recover a major
22 portion of the costs allocated to solar customers.

23
24 **Q33: What rate design structures exist that can accurately reflect a solar customer's**
25 **reduced cost of service and also provide an incentive for peak demand reduction?**

26 A33: The 33% reduction in costs calculated in Table 3 can be matched accurately by a two-part
27 TOU rate, such as APS's existing ET-2 rate, simply by adjusting the amount of costs
28 collected in the on-peak and off-peak rates. The first step in constructing such a rate is to
29 calculate the change in billing determinants when the average residential customer adds
30 solar, for various types of rate elements. These are shown in **Table 4**, which assumes an
31 on-peak TOU period of 2 p.m. to 7 p.m., which SEIA recommends in Section IV of this

testimony. Like Table 2, the results in Table 4 also are based on an analysis of the APS 2015 solar census data.

Table 4: Change in Customer Billing Determinants (kWh Energy and kW Demand)

Billing Determinant	Solar Customers On Energy-based Rates (25,837 customers)			Solar Customers On Demand-based Rates (919 customers)			Weighted Average
	Pre Solar	Post Solar	Percent Change	Pre Solar	Post Solar	Percent Change	Percent Change
Energy (kWh) Summer (May-Oct) On-peak (2-7 p.m.)	2,077	1,221	-41%	3,191	2,078	-35%	-41%
Energy (kWh) Annual (12 months) All hours	16,531	11,480	-31%	27,782	20,707	-26%	-30%
Max Demand (kW) Avg. of 12 months On-peak (2-7 p.m.)	5.6	4.8	-14%	7.5	6.7	-11%	-13%

From the data in Table 4, a two-part volumetric TOU rate similar to the APS ET-2 rate can be constructed that will accurately reflect solar customers' 33% reduction in their costs. This TOU rate combines an annual energy rate that applies in all hours, plus a rate adder that applies only in the on-peak TOU period. We assign 37% of production demand, transmission, and distribution costs to the volumetric on-peak rate adder (with a 2 p.m. to 7 p.m. on-peak period), with the remaining 63% of these costs to the annual rate across all hours. This design allows solar customers to reduce these costs by 34%.²²

When combined with energy costs, the average solar customer will achieve the cost-based 33% reduction in costs shown in Table 3 above. **Table 5** summarizes the cost impacts of this rate design.

//

²² The -34% reduction in production demand, transmission, and distribution costs is based on a -40.9% reduction for the 37% of these costs in the on-peak rate, plus a -30.3% reduction for the 63% of such costs collected through the annual energy rate. The math is $-34\% = -40.9\% \times 37\% + -30.3\% \times 63\%$.

Table 5: Change in APS Residential Costs due to Solar – Two-Part TOU Rate

Cost Element	Basis for Cost Allocation	Average Cost (\$/MWh)	Reduction due to Solar (%)
Energy	Energy use	\$33.57	-30%
Production Demand	4CP / 4 NCD	\$37.26	-34%
Transmission	4CP	\$8.50	-34%
Distribution – Primary & Substations	4 NCD	\$14.51	-34%
Distribution – Secondary	Sum of Individual Max	\$7.60	-34%
All Elements (Weighted by Average Cost)			-33%

Q34: Have you calculated the ET-2 rates that would result from this cost-based rate design for solar customers?

A34: Yes, I have. These cost-based rates are presented in **Table 6**, and are compared to both current ET-2 rates and the “transition” ET-2 rates that APS has proposed in this case for existing, grandfathered solar customers. The “transition” ET-2 rates maintain a noon to 7 p.m. on-peak period.

Table 6: ET-2 Two-Part TOU Rates (\$ per kWh)

	ET-2 TOU Rates		
	Current	APS Transition	SEIA Proposed
On-peak period	Noon – 7 p.m.	Noon – 7 p.m.	2 p.m. – 7 p.m.
Summer Rates			
On-peak	0.24477	0.29201	0.29271
Off-peak	0.06118	0.07299	0.09001
Winter Rates			
On-peak	0.19847	0.23677	0.18872
Off-peak	0.06116	0.07296	0.09001

Q35: What is SEIA’s recommendation for the design of rates applicable to solar customers in this case?

A35: Solar customers should have the option of the ET-2 rate presented in the final column of Table 6 – a two-part, volumetric TOU rate with a 2 p.m. to 7 p.m. peak period. This rate is cost-based for solar customers, and will not shift costs to other ratepayers.

1 **Q36: Given that at least a small portion (9%) of APS's distribution costs are assumed to**
2 **be driven by customers' maximum individual demands, wouldn't it be most**
3 **accurate to assess at least those costs through an on-peak demand charge based on**
4 **customers' individual maximum on-peak demand?**

5 A36: From a strict cost causation perspective, this argument can be made. Of course, this
6 would result in a much smaller demand charge than APS has proposed in the R1, R2, and
7 R3 rates. A demand charge that recovered just secondary distribution costs from
8 residential customers would be no greater than \$1.94 per kW-month, far less than the
9 demand charges that APS has proposed, as shown in Table 1 above.

10
11 However, adherence to cost causation is only one of the Bonbright principles.
12 Commissions often have kept fixed charges low in order to provide customers with a
13 stronger signal to reduce energy usage, despite strict cost causation arguments in favor of
14 larger fixed charges. As I will explain in the next sections, there are more accurate and
15 appropriate rate designs available, as well as serious problems with small customers
16 understanding, accepting, and responding to mandatory demand charges.

17
18 **C. Targeted Volumetric TOU Rates, Such as CPP Rates, Are A Superior Rate**
19 **Design Choice to Demand Charge-based Three-Part Rates.**
20

21 **Q37: Are there ways to have volumetric TOU rates that send better price signals to**
22 **encourage customers to shift load away from the on-peak period?**

23 A37: Yes. CPP rates charge a very high, volumetric rate to customers in a limited number of
24 high-demand on-peak hours each year that the utility declares on a day-ahead basis. CPP
25 rates represent a far more accurate, targeted, and cost-based means to charge customers
26 than traditional 15- or 60-minute on-peak demand charges. Demand charges provide the
27 same price signal in all on-peak hours, including the on-peak hours on days when loads
28 are not high and reductions in usage are less important. In comparison, CPP rates target
29 the critical hours only on days when demand is very high and reductions in on-peak
30 usage have the greatest value to the utility.

1 **Q38: Does the alternative of more precisely targeted CPP rates provide a perspective on**
2 **whether the Commission should be moving toward mandatory demand charges,**
3 **given how metering technology has evolved?**

4 A38: Yes. The alternative of CPP rates shows that demand charges are not necessarily the best
5 means to recover capacity-related costs that are driven by a customer's demand for
6 power. Fundamentally, measuring a customer's "demand" is simply measuring its
7 energy use over a different, shorter time period (15 or 60 minutes) than the standard
8 measure of energy over a time-of-use period of multiple hours, or a standard billing
9 period of one month. Thus, a customer with a demand of 4 kW is really just using 1 kWh
10 of energy every 15 minutes or 4 kWh of energy each hour. From this perspective, there
11 is nothing inherently more accurate with charging customers for demand (kW) than
12 energy (kWh). Nor is a customer's maximum 60-minute on-peak demand over a monthly
13 billing period necessarily significant for cost causation, unless it occurs at a time when
14 demand on the system or local feeder is high. The 15- or 60-minute maximum demand
15 charge is simply a traditional way that utilities have charged large customers for certain
16 costs given the limitations on metering equipment that existed historically.²³ However,
17 demand charges are increasingly obsolete because, with new metering and
18 communications technologies, focused and targeted time-varying rates will be much
19 more accurate than traditional maximum demand charges. There is no doubt that it more
20 accurately reflects cost causation to bill a customer a high rate during the peak hours on a
21 peak or near-peak day, than to charge a maximum demand charge based on 60 minutes of
22 usage that may not occur when the system is stressed. It is usage in high-demand hours
23 that causes the utility to incur both the highest energy costs as well as capacity-related
24 costs throughout the system, for generation, transmission, and distribution. In sum, given
25 new metering and communications technologies, the Commission should re-evaluate the
26 role in rate design of traditional demand charges.

27
28 **Q39: Does APS have experience with CPP rates?**

²³ Demand charges date from the infancy of the electric industry, when meters could only record maximum usage, with no means to record the time when that maximum usage occurred. As a result, utilities charged for what they could measure, and developed rate designs based on the limited capabilities of the meters of the day.

1 A39: Yes. APS has run a residential CPP pilot program since 2010. The program evaluation
2 report for 2015 shows that participants reduced their demands between 2 p.m. and 7 p.m.
3 on event days by 12%.²⁴ APS is now proposing to continue the CPP program in
4 preference to its peak time rebate and supper-peak TOU programs “because it
5 successfully incented load shifting during critical hours, provides more accurate
6 incentives and is easier to implement than peak time rebates.”²⁵ The CPP pilot achieved
7 a significantly greater level of load reduction than APS found to occur when customers
8 switched from two-part to three-part rates (a 3% to 4% reduction),²⁶ in addition, the CPP
9 load reductions occurred during hours of critically high demand, which may not have
10 been the case with the load reductions from moving to three-part rates.
11

12 CPP rates are also a natural progression in the design of APS’s TOU rates, which
13 have included an option with a shorter “super-peak” TOU period with a rate higher than
14 the on-peak rates in other schedules. APS’s TOU rates have been far more popular with
15 APS’s residential customers than its three-part residential rate.
16

17 **Q40: Have other states had significant experience with CPP rates?**

18 A40: Yes. California is moving toward default TOU rates for residential customers, and has
19 established CPP rates as the default for all commercial rate classes. National Grid, a
20 major New England electric distribution company, recently reported positive results for
21 its *Smart Energy Solutions Pilot*, which featured TOU rates with an overlay of CPP rates
22 during high-demand summer periods.²⁷ The pilot achieved load reductions of 10% to
23 31% among active program participants during critical peak periods, as well as an overall
24 energy use reduction of almost 5%, with a high degree of customer satisfaction.²⁸
25

²⁴ This report, filed May 31, 2016 in Docket No. E-01345A-11-0250, is in the APS response to Staff DR 5.22. See page 3 for the reported 12% load reduction in critical peak hours.

²⁵ See APS response to Staff DR 5.22.

²⁶ APS Direct Testimony (Miessner), at p. 20.

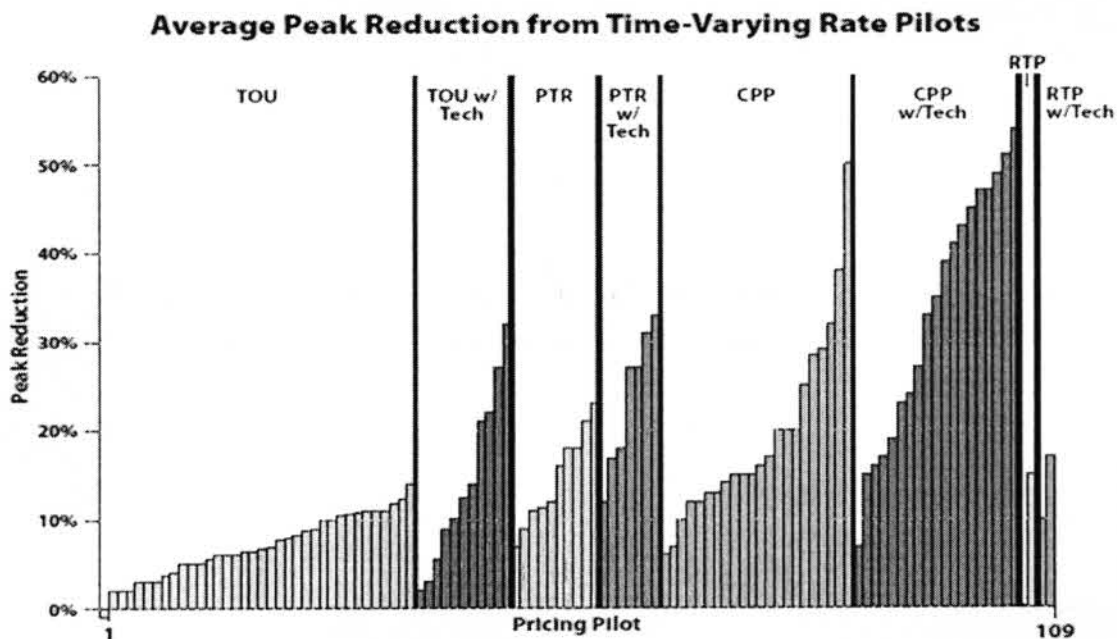
²⁷ See National Grid Smart Energy Solutions Pilot: Interim Evaluation Report, D.P.U 10-82 (Feb. 22, 2016), http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=10-82%2fNGrid_Smart_Energy_Solutions_R.pdf.

²⁸ *Ibid.*, at p. 5 and Figure E-1.

1 **Q41: Is there evidence that targeted TOU rates such as CPP are likely to provide larger**
2 **demand reductions than standard TOU rates?**

3 A41: Yes. **Figure 2** below compares peak demand reductions from various pilot programs
4 examining different types of TOU and CPP rates, both with and without enabling
5 technology. The figure is from a paper co-authored by Mr. Faruqui of the Brattle Group,
6 a witness for APS in this case.²⁹

7
8 **Figure 2: Results of Pilot Programs for Various Time-Varying Rate Designs**



9
10
11 **D. There Are Significant Customer Acceptance Issues With Mandatory**
12 **Demand Charges.**

13
14 **Q42: What evidence is available on small customers' acceptance and understanding of**
15 **demand charges?**

16 A42: First, there is the fact that APS has offered both two- and three-part residential rates for a
17 number of years. The two-part TOU rates have been significantly more popular, as

²⁹ Ahmad Faruqui *et al.*, *Time-Varying and Dynamic Rate Design*, (Brattle Group and the Regulatory Assistance Project, 2012), at page 28.

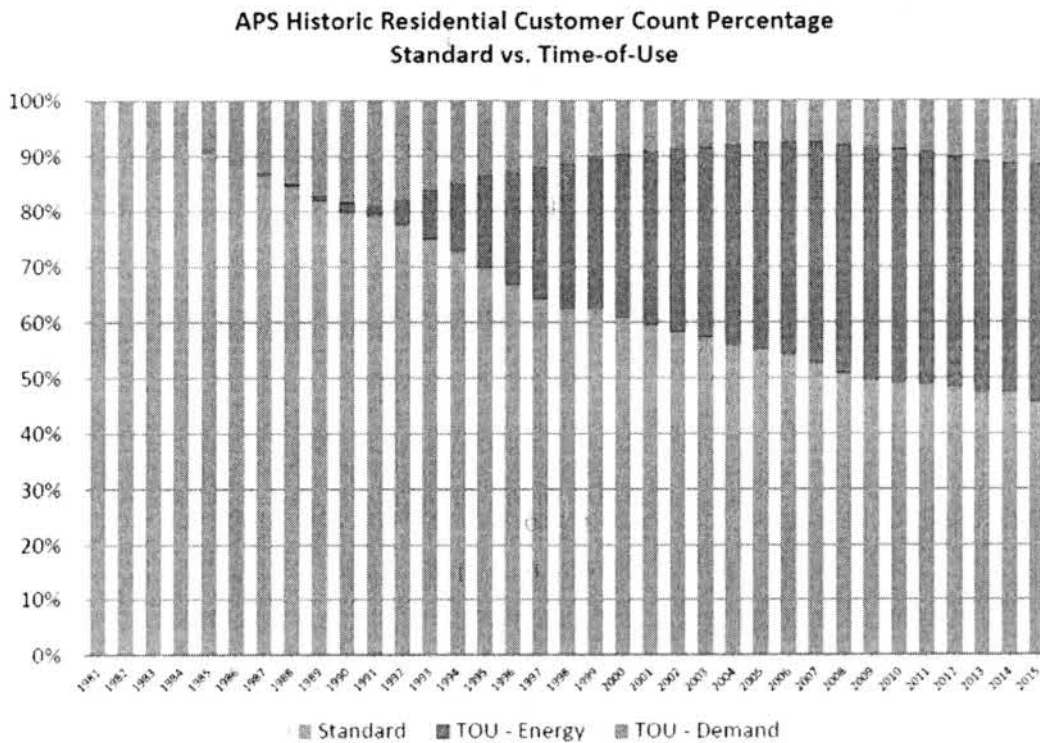
shown by residential customers choosing them by almost a four-to-one over the available three-part rates, as summarized in **Table 7** using 2015 test year data.

Table 7: APS Residential Rate Choices in 2015³⁰

Type of Rate	Rate	Status	Number of Customers	Share (%)
Tiered	E-12	Open	427,743	45%
2-part TOU	ET-1	Closed	123,431	13%
	ET-2	Open	284,825	30%
3-part TOU with demand charge	ECT-IR	Closed	23,662	2%
	ECT-2	Open	88,874	9%
Total			948,535	100%

Over time, APS's two-part rates have become progressively more popular, taking market share from both tiered and three-part rate designs, as shown by the figure reproduced below from the APS Long-term Rate Plan, attached to Mr. Snook's testimony.

Figure 1



³⁰ From APS Schedule H-4, Page 1 of 82.

1 Both APS's two-part and three-part rates have been effective at incenting beneficial
2 reductions and shifts in customer loads. APS's *2015 Demand Side Management (DSM)*
3 *Progress Report* estimates that in 2015 its TOU rates achieved 159 MW in load
4 reductions and 687,660 MWh in energy savings.³¹ This amounts to a load reduction of
5 0.31 kW and 1,320 kWh in annual energy savings per residential customer on TOU rates.
6

7 **Q43: Does the modest 11% penetration of customers electing residential rates with a**
8 **demand charge indicate significant customer acceptance of such a rate structure?**

9 A43: No, it does not. This is particularly true given that APS's customer service
10 representatives use a rate evaluation tool to help residential customers self-select the rate
11 option that benefits them the most. As a result, the customers selecting the ECT-1 and
12 ECT-2 rates tend to be larger, higher-load-factor customers that benefit structurally from
13 a demand charge rate and have a greater variety of electric demands (such as pool pumps)
14 that can be controlled and sequenced automatically to maintain a high load factor. This
15 experience does not indicate that demand charge-based rates will be well-received by the
16 89% of residential customers who have not selected a demand-based rate and are unlikely
17 to benefit structurally.
18

19 **Q44: APS's witness Mr. Meissner cites a study that APS performed of about 1,000**
20 **customers who switched from a two-part TOU rate to the three-part ECT-2 rate.**
21 **The study shows that the customers reduced their maximum demands by 3% to**
22 **4%, and had lower bills.³² Do you have any concerns about this study?**

23 A44: Yes. First, 40% of the customers who switched actually increased their demand.³³
24 Second, over 70% of the bill savings appear to be because these customers had high load
25 factors and would have been better off under the ECT-2 rate to begin with.³⁴ Third, one

³¹ This report was filed on March 1, 2016 in Docket No. E-00000U-16-0069. See page 72.

³² See APS Testimony (Miessner), at p. 20.

³³ See workpapers for this study, from AURA DR 1.30, at "Load & Bill Impacts" tab.

³⁴ Of the average summer bill savings of \$29.88 per month, just \$4.22 came from demand reduction. A slightly greater amount of bill savings (\$4.53 per month) came from reductions or shifts in energy use that would be incented even more strongly under two-part TOU rates. The remaining summer bill savings of over \$20 per month resulted from the fact that these customers should have been on the ECT-2 rate in the first place.

1 can expect customers who make the effort to switch rates to be relatively motivated to
2 take steps to reduce or shift their usage. APS's study would be more convincing if it had
3 controlled for this factor by also looking at customers who switched in the other direction
4 – from ECT-2 to ET-2 – and showed that those customers realized fewer benefits than
5 those who switched from ET-2 to ECT-2.³⁵ However, APS did not do this study.³⁶

³⁵ In fact, the average customer in this data set would have realized greater summer bill savings from demand and usage reductions had they remained under the ET-2 rate (\$10.23 per month), instead of switching to ECT-2 (\$8.75 per month).

³⁶ APS response to SEIA DR 5-1, included in **Attachment RTB-3**.

1 //

2 //

3 //

4 //

5 **Q46: Are you aware of research from other states on customer attitudes toward demand**
6 **charges?**

7 A46: Yes. In Colorado, Public Service of Colorado (PSCo) recently conducted a focus group
8 on a pilot residential rate design that combined TOU rates and a demand charge. The
9 results of that survey indicate that the combination of a demand charge and a specific
10 time-of-use period in which it applies is potentially confusing to customers and
11 challenging for customers to manage.³⁷

12

13 In California, in 2013 the three major investor-owned electric utilities in the state
14 commissioned a customer survey as part of the CPUC's comprehensive rulemaking
15 proceeding on residential rate design.³⁸ This study concluded that a demand charge "was
16 confusing" to participants, who ended up making inaccurate comparisons to a fixed
17 monthly service fee because they failed to comprehend that a demand charge "varies
18 based on kW demand levels."³⁹ In this rulemaking San Diego Gas & Electric (SDG&E)
19 proposed a tiered customer charge to recover distribution costs, with the tier applicable to
20 a customer based on the customer's maximum demand in the prior month. The CPUC
21 rejected the SDG&E proposal, even for inclusion in California's pilot programs on new
22 residential rate designs, as beyond the anticipated scope of residential rate design and as
23 potentially distracting from the CPUC's central focus on expanding the use of volumetric
24 TOU and CPP rates.⁴⁰

25

26 Subsequently, in 2015, SDG&E conducted a survey of customer preferences for a
27 new net metering (NEM 2.0) tariff in California. This survey only looked at possible

³⁷ Colorado PUC Docket No. 16AL-0048E (Phase II), PSCo Testimony of Alice Jackson Testimony, Exhibit AKJ-1, at p. 25 of 30.

³⁸ CPUC Docket R. 12-06-013.

³⁹ Hiner & Partners, Inc. "RROIR" Customer Survey, at 22 (April 16, 2013).

⁴⁰ See CPUC Decision No. 15-07-001 (issued July 3, 2015), at pp. 182-184 and Finding of Fact 160.

1 new structures for the NEM 2.0 tariff, and did not include a continuation of the existing
2 NEM 1.0 tariff based on a retail rate credit using the existing volumetric rate structure.
3 The possible new NEM 2.0 structures that SDG&E tested included (1) a feed-in tariff
4 with a set price for all DG output, (2) a demand charge, and (3) an installed capacity
5 charge based on the installed kW of DG capacity. Significantly, the simplest structure –
6 the feed-in tariff, although not as simple as the existing NEM 1.0 – was favored over
7 demand charges or installed capacity charges by wide margins – by 4-to-1 over a demand
8 charge and by 5-to-1 over an installed capacity charge. The survey concluded that, for
9 customers, the key drawbacks of the demand charge are that it is “confusing,”
10 “unpredictable (may pay more),” and “can be difficult to change behavior” to reduce your
11 maximum 15-minute demand.⁴¹ One of the respondents to the SDG&E survey
12 summarized the problematic behavioral economics associated with extending mandatory
13 demand charges to residential customers:

14 I don't like anything about it. I will constantly have to monitor how many
15 electric appliances are being used at each time, and will have to become the
16 “electricity police” in my household and make sure that each family member
17 is complying.⁴²
18

19 In January 2016, the CPUC found that the utility proposals to levy demand charges or
20 installed capacity fees on DG customers would face difficulties with customer
21 acceptance, were not cost-based, and would be contrary to the CPUC’s rate design goals
22 that focus on implementing TOU rates.⁴³
23

24 **Q47: Are you aware of any states that have mandated the use of demand-charge-based**
25 **rates for all residential or small commercial customers?**

26 A47: No, I am not. The survey attached to Mr. Faruqui’s testimony for APS shows that there
27 are only three small U.S. utilities – two rural cooperatives in Kansas and South Carolina
28 and one town in Vermont with a total of 65,000 customers – which mandate three-part

⁴¹ Hiner & Partners, *Final Report: Solar (NEM) Rate Preferences Survey Results*, at Slide 8 (June 2015).

⁴² *Id.*, at Slide 24.

⁴³ See CPUC Decision No. 16-01-044, at 76-79,
<http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K285/158285436.pdf>.

1 rates for all residential customers.⁴⁴ Of these three utilities, the largest one, the Mid-
2 Carolina Electric Cooperative (MCEC) with 55,000 customers, specifically exempts net
3 metered solar DG customers from the demand-based rate that is mandatory for all other
4 customers. MCEC granted this exemption, in the words of its CEO, ““If we did the
5 demand charge, if it was sunny 29 days out of 30, [solar customers] would have low
6 demand except for that one cloudy day, their demand would be high. We would
7 essentially be penalizing them for that one day of cloudy weather.” For its net metered
8 solar customers, MCEC has replaced the demand charge with a relatively high
9 volumetric, on-peak TOU rate.⁴⁵

10
11 Please also see **Attachment RTB-2**, which summarizes recent cases involving or
12 related to demand charges in other states. I have been involved in all of these cases.⁴⁶

13
14 **Q48: Are there other practical customer acceptance issues with rate designs featuring**
15 **demand charges?**

16 A48: Yes. Demand charges substantially complicate customers' and vendors' ability to
17 analyze and project the bill savings from demand-side programs, including energy
18 efficiency, demand response, and DG. For example, demand data for typical home
19 energy uses and appliances is not readily available; the usage of “Energy Star” appliances
20 is reported in terms of annual kWh usage, not the short-term power draw. Understanding
21 and accepting on-peak demand charges will require customers to become familiar with
22 data on their hourly demands, as well as on when they use electricity. Customers will
23 have to analyze and understand much more data on their energy use to appreciate when
24 their demand peaks and what the hourly profile of their usage is.

⁴⁴ APS Direct Testimony (Faruqui), at Attachment AJF-2DR: *Summary of Residential Three-Part Tariffs*.

⁴⁵ See https://www.cooperative.com/public/bts/renewables/Documents/NRECA_RateCasestudies.pdf, at p. 27.

⁴⁶ Please note that, in addition to proposals to implement three-part rates, there have also been several proposals to adopt tiered fixed monthly charges, with the tiers scaled to various measures of residential customer demand or energy usage. I would characterize these as “proto-demand charges.” The utilities that have proposed such tiered fixed charges generally lack the metering to implement 15- or 30-minute demand charges, but have justified the tiered fixed charges as a first step toward demand charges until the necessary advanced metering infrastructure can be installed. These cases are also listed in Appendix E.

1
2 **Q49: Will APS's proposed demand charges significantly change customers' incentives to**
3 **reduce on-peak usage?**

4 A49: Yes. APS's proposed 60-minute demand charge provides a customer with an incentive to
5 reduce their usage only in those hours when the customer might reach their maximum
6 hourly usage for the month. For solar customers, the maximum hourly usage for the
7 month may occur on a cooler, cloudy day when their solar output is low and system
8 demand is similarly low, rather than on a hot, sunny day when demand is peaking but
9 solar output is also strong. This results in a perverse incentive to conserve on non-peak
10 days. Moreover, with a demand-based rate the customer has a significantly reduced
11 incentive to conserve energy on-peak so long as the customer remains below the
12 maximum hourly usage which the customer has reached earlier in the month. Finally,
13 APS's proposed requirement that solar customers must take service under the R3 rate
14 design means that many customers considering solar will have to change rate designs if
15 they elect to install solar.

16
17 **Q50: How are volumetric TOU rates superior to demand charges in providing an**
18 **understandable and consistent price signal to customers?**

19 A50: A customer under volumetric TOU rates will see a consistent price signal in all on-peak
20 hours of the month. With the overlay of CPP rates, this consistent price signal can be
21 made sharper and more accurate on those days when reductions in on-peak usage are
22 most valuable. Further, a customer who installs a DG system will continue to see, on the
23 margin and in many hours, exactly the same price signal from two-part rate design that
24 the customer saw before adding solar.⁴⁷ Customers find it easy to understand that the
25 same signals which they receive under the regular rate design will continue unchanged if
26 they install a solar system. This "transparency" of the price signals is a strong reason to
27 continue to rely on volumetric TOU rates. This also means that the utilities, the solar

⁴⁷ The Commission's decision to establish a separate export rate introduces the new complexity that a solar customer is likely to face an export rate that differs from the retail rate. This is not the case under standard net metering, where the import and export rates are the same, i.e. the volumetric retail rate.

1 industry, and the Commission do not have to educate solar customers about rate design in
2 any way that is different than non-solar customers.

3
4 **Q51: Has the Commission expressed concerns about bill impacts and customer**
5 **acceptance in reviewing previous proposals to implement mandatory residential**
6 **demand charges?**

7 A51: Yes. In 1980, the Commission mandated the demand-based EC-1 rate for all new APS
8 residential customers who were adopting a new technology – central air conditioning.⁴⁸
9 Three years later, in 1983 in Decision 53615, the Commission removed this mandate "in
10 response to complaints that the mandatory nature of the EC-1 rate produced unfair results
11 for low volume users." This order also found that removing the mandate would "alleviate
12 the necessity for investment by low consumption customers in load control devices to
13 mitigate what would otherwise be significant rate impacts under the EC-1 rate."⁴⁹

14
15 Last year, in Order 75697 in the UNSE general rate case, at page 65, the
16 Commission found that "[t]he public distrust or antipathy to the proposal has convinced
17 the Company and the Commission that any transition to three part rates will require a
18 massive public education effort before we can say with any degree of certainty that
19 mandatory residential demand rates in UNSE's service territory are in the public interest."

20
21 **Q52: In the UNSE case, what did the Commission adopt in lieu of mandatory demand**
22 **charges?**

23 A52: The Commission found that a more moderate path is to provide for optional TOU or
24 three-part rates:

25 Even though we do not approve mandatory residential or SGS demand rates, we
26 believe that the time is ripe for a more modern rate design. Before turning to
27 mandatory three-part residential rates, however, we find that the better, more
28 tempered path to modernity is to move more customers to TOU rates or three-part
29 rates. Appropriately designed TOU rates or three-part rates should allow better
30 recovery of costs, and send the correct signals about the cost of service and
31 encourage customers to shift their loads to off-peak times. By shaving the peak,

⁴⁸ See Decision 51472, dated September 4, 1980.

⁴⁹ See Decision 53615, at pp. 7-8.

1 the utility and its ratepayers can save on investments in generation, transmission
2 and capacity.⁵⁰
3

4 **Q53: What do you conclude about the correct focus for APS's efforts to evolve its rate**
5 **design for small customers?**

6 A53: My conclusion is that it is preferable to spend limited customer education resources on
7 implementing more accurate, more cost-based time-varying rates, including CPP rates.
8

9 **Q54: Does SEIA oppose APS continuing to offer optional three-part rates to residential**
10 **customers?**

11 A54: No. SEIA generally supports offering small customers a reasonable range of cost-based,
12 optional rate designs. However, an on-peak demand charge based on individual
13 customer's maximum demand should only cover those costs that are driven by such
14 individual demands. As noted above, for APS's residential customers, such a demand
15 charge would not exceed \$2 per kW-month to cover secondary distribution costs.
16

17 **Q55: What other rate designs should APS offer to residential customers?**

18 A55: APS should continue to offer its popular ET-2 rate – a two-part TOU rate – to residential
19 customers, including to solar customers. SEIA also does not oppose APS's proposal for a
20 flat two-part rate for small customers using less than 600 kWh per month.
21

22 **Q56: At the conclusion of this case, will there be any reason to maintain the \$0.70 per**
23 **kW-month installed capacity charge on solar customers that the Commission**
24 **implemented in Decision 74202?**

25 A56: No, there will not. As set forth above, the continuation of the ET-2 rate with a revised
26 on-peak period will provide an accurate, cost-based rate for solar customers. Further, the
27 Commission has taken steps in Decision 75859 to make changes to the export rate to
28 align that rate with the value that solar customers' exported power provides to the APS
29 system. Accordingly, now that the Commission has comprehensively addressed on a
30 more permanent basis the "cost shift" issues related to solar DG, there is no need to

⁵⁰ Order 75697, at p. 65.

1 maintain the interim \$0.70 per kW-month installed capacity charge on solar customers
2 that the Commission adopted in Decision 74202.

3
4 **E. APS's Proposed Rate Design for DG Customers May Violate PURPA.**

5
6 **Q57: Are small customers who install DG by definition qualifying facilities (QFs) under**
7 **PURPA?**

8 A57: Yes. I am not a lawyer, but I am aware that customers who install renewable DG systems
9 (solar or wind) are, by definition, qualifying facilities (QFs) under the Public Utilities
10 Regulatory Policies Act of 1978 (PURPA). For a customer installing a system with a net
11 power production of 1 MW or less, I understand the designation as a qualifying small
12 power production facility (and therefore a QF) is automatic with no filing at the Federal
13 Energy Regulatory Commission (FERC) required.

14
15 **Q58: What are the PURPA requirements for the sale of power to QFs?**

16 A58: I am not a lawyer, but I have done a significant amount of work for QF clients, and I
17 understand that the rates for the sale of power from an electric utility to the QFs on its
18 system must comply with the FERC rules implementing PURPA. Generally, these rules
19 specify that the rates for sales to QFs must be non-discriminatory. QFs have the right to
20 purchase supplementary power (defined as the power the QF needs beyond what the QF's
21 own on-site generator can supply) at rates which are just and reasonable, that do not
22 discriminate against QFs in comparison to the utility's other retail rates, and that are
23 based on accurate data and consistent system-wide costing principles.⁵¹ Significantly,
24 the FERC rules create a safe harbor against claims of discrimination to the extent that
25 QFs pay the same rates as similar customers:

26 *Rates for sales which are based on accurate data and consistent*
27 *systemwide costing principles shall not be considered to discriminate*
28 *against any qualifying facility to the extent that such rates apply to the*
29 *utility's other customers with similar load or other cost-related*
30 *characteristics.*

⁵¹ 18 CFR §292.305(a) and (b). Also see "What are the benefits of QF status?" on the FERC website:
<http://www.ferc.gov/industries/electric/gen-info/qual-fac/benefits.asp>. Supplementary power is power
that the QF/DG customer regularly purchases from the utility in addition to its on-site production.

1
2 The creation of a separate DG/QF customer class with distinct rates from other residential
3 customers represents a move away from this safe harbor, as residential customers who
4 install DG (and thus become QFs and move into a new residential DG/partial
5 requirements class) would no longer be considered "similar" to, and may no longer pay
6 the same rates as, other residential customers.

7
8 **Q59: Are there reasons why APS's proposed residential DG class may be considered**
9 **discriminatory under PURPA?**

10 A59: Yes. APS's cost allocation and rate design for residential DG customers could
11 discriminate unduly against such small QFs in comparison to the rates for other partial
12 requirements QF customers on the APS system. As I noted above, in comparison to its
13 treatment of residential solar customers, APS appears to propose a different cost
14 allocation for small commercial customers who install solar, and does not appear to place
15 such customers into a separate sub-class. Large partial requirements customers who are
16 served from on-site cogeneration or renewable QFs also are not placed into a separate
17 customer class to which costs are allocated separately from similar customers who are not
18 QFs; instead, these partial requirements customers pay the same rates as other customers
19 in the class for service which supplements their on-site generation, plus riders for other
20 services like backup and maintenance power.⁵² The FERC rules for sales to QFs make
21 clear that, to meet PURPA's non-discrimination standard, all rates for sales to QFs must
22 be based on "consistent systemwide costing principles."⁵³ The creation of a different cost
23 allocation and rate design for residential DG customers, in comparison to other partial
24 requirements QF customers on the APS system, appears to be inconsistent and
25 discriminatory, and thus may violate this FERC rule.

26
27 **Q60: Are there other ways in which APS's proposed COSS appears contrary to FERC**
28 **regulations implementing PURPA?**

⁵² Back-up power and maintenance power refer to power purchased when the QF generation is not operating due to forced or planned outages, respectively.

⁵³ See 18 CFR §292.305(a)(2).

1 A60: Yes. APS's use of total site load to allocate demand-related costs to DG customers
2 appears to be contrary to FERC's PURPA regulations. As I discuss above, APS
3 erroneously concludes that it must build a system to serve the total site loads of all solar
4 customers in case all solar units fail at the same time or all solar systems have zero output
5 in all of the critical hours that drive the utility to incur costs. However, the PURPA
6 regulations specifically prohibit rates for service to QFs that are "based upon an
7 assumption (unless supported by factual data) that forced outages or other reductions in
8 electric output by all qualifying facilities on an electric system will occur simultaneously,
9 or during the system peak, or both."⁵⁴ APS offers no evidence that the simultaneous
10 outage of all DG systems is even remotely plausible. Diversity among distributed
11 generators makes it unnecessary for the utility to incur capacity costs, in the FERC's
12 words, "on the assumption that every facility will use power at the same moment."⁵⁵
13

14 **Q61: But doesn't APS propose to provide cost-of-service credits to solar customers to**
15 **capture the cost savings which rooftop solar systems provide to the APS system?**

16 A61: Yes, but APS does not calculate these credits accurately or consistently, for example, by
17 using the loads at the time of solar DG sub-class peak instead of when the entire
18 residential class peaks.
19

20 **Q62: How can APS remedy this discriminatory treatment of DG customers?**

21 A62: APS should calculate the cost of service for solar customers based on the loads APS
22 actually delivers to DG customers, just as it does for all other customers. APS's
23 delivered loads include all solar customers' actual historical demand on the APS system,
24 including the effect of added demand when a solar system was out of service or when it
25 was cloudy. The delivered load data is the evidence-based, PURPA-compliant
26 foundation for allocating costs because it "reflects the probability that the [NEM
27 customer] will or will not contribute to the need for and the use of utility capacity."⁵⁶

⁵⁴ See 18 CFR 292.305(c)(1).

⁵⁵ 45 Fed. Reg. at 12229. FERC also has stated that its rule for sales to QFs "prohibits utilities from basing rates on the assumption that qualifying facilities will impose demands simultaneously and at a system peak unless supported by factual data." *Ibid.*

⁵⁶ See 45 Fed. Reg. at 12228.

1 APS also should allocate production and distribution costs to solar DG customers based
2 on loads at the time of the residential class peak, on the same basis as other residential
3 customers.
4

5 IV. CHANGES TO APS'S TOU PERIODS
6

7 **Q63: APS has recommended a change to a 3 p.m. to 8 p.m. summer on-peak period, from**
8 **the present noon to 7 p.m. on-peak period used for the most popular ET-2**
9 **residential TOU rate. What justification does the utility provide for this change?**

10 A63: APS discusses how the addition of significant solar resources to its system, and to other
11 western utilities including those in California, is shifting the peak in APS's "net load"
12 (total system load less solar resources) to later in the day, particularly in the summer
13 months. APS examines projections for its load shape and for Palo Verde energy prices in
14 2018, and concludes that its on-peak period should be shifted to 3 p.m. to 8 p.m.⁵⁷
15

16 **Q64: Has the Commission recently addressed this issue for other utilities?**

17 A64: Yes, the Commission adopted a shorter 3 p.m. to 7 p.m. summer on-peak period for
18 UNSE, plus winter on-peak periods of 6 a.m. to 9 a.m. and 6 p.m. to 9 p.m.⁵⁸ In that
19 case, RUCO and other intervenors recommended a shorter, four-hour on-peak period to
20 promote customer acceptance of TOU rates.
21

22 **Q65: Do you agree that APS's current noon to 7 p.m. on-peak period should be revised?**

23 A65: Yes, in part for the same general reasons outlined by APS. However, additional factors
24 beyond energy prices and net loads should be considered in determining the best set of
25 TOU periods for APS. My evaluation of all of the factors that impact the choice of an
26 on-peak TOU period for APS lead me to recommend a 2 p.m. to 7 p.m. on-peak period
27 for APS.
28

⁵⁷ See APS Testimony (Wilde), at pp. 4-6 and 12-14.

⁵⁸ Order 75697, at p. 66.

1 **Q66: What additional factors should be considered in determining the best set of TOU**
2 **periods for APS?**

3 A66 TOU periods are used to design rates that cover all elements of the utility's costs –
4 energy, generation (production) capacity, transmission, and distribution. Thus, in
5 choosing TOU periods it is important to consider the time profile of key metrics for all of
6 these costs. This is what I have done in **Figures 3 and 4**, for the summer (May-October)
7 and winter (November-April) seasons, respectively. These figures show the summer and
8 winter hourly profiles for each of the major components of APS's costs, with the hourly
9 profiles weighted by the relative level of these costs for APS's residential class. The
10 hourly profiles for each cost component are based on the following metrics:

- 11 • **Production Energy** – Palo Verde energy prices for 2018;
- 12
- 13 • **Production demand** – APS hourly loss of load probabilities (LOLPs) for 2018,
14 which show the relative need for capacity across the hours of the year;
- 15
- 16 • **Transmission** – peak capacity allocation factors (PCAFs)⁵⁹ based on the top 10%
17 of APS system loads in 2018; and
- 18
- 19 • **Distribution** – PCAFs based on the top 10% of APS 12 kV distribution
20 substation loads in 2015.
- 21

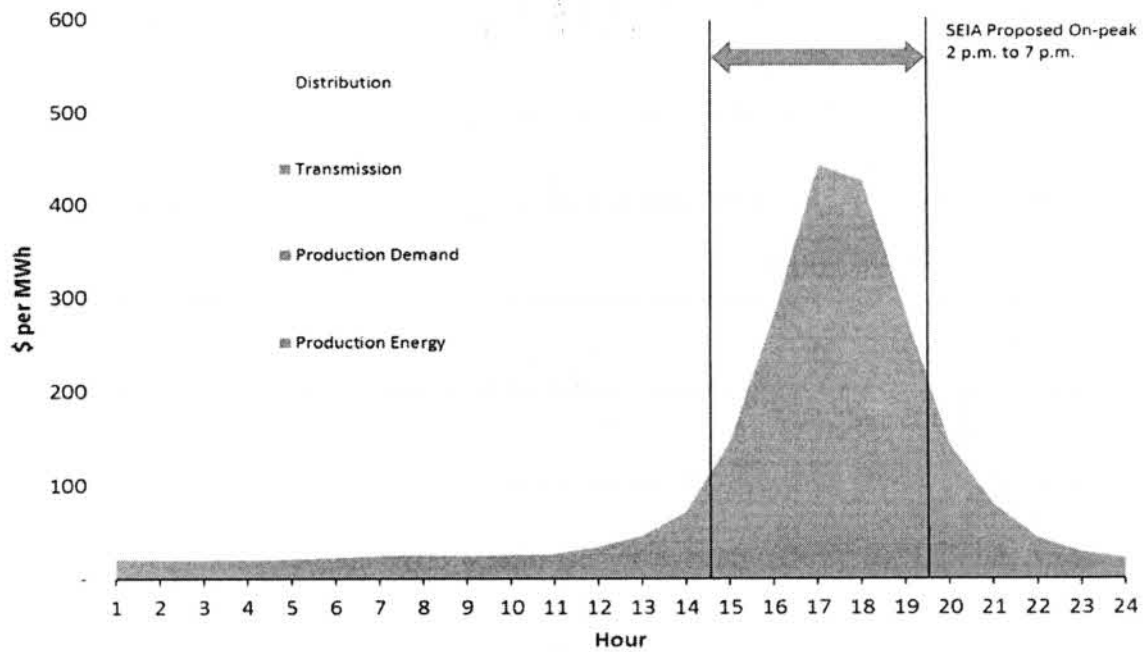
⁵⁹ PCAFs are a set of hourly allocation factors for the hours with loads that are above a certain threshold (here, we used 90% of the annual peak hourly load), with each hour with a load above this threshold load weighted by the amount by which the load in that hour exceeds the threshold. SEIA calculated a PCAF distribution for the hourly loads at each APS 12 kV substation, and then an overall PCAF distribution for the entire APS system based on the weighted average of the individual substation PCAFs. PCAF allocations are a standard technique for determining the relative contribution of hourly loads to peak demands. The formula for a PCAF allocation is as follows:

$$PCAF_s(h) = \frac{(Load_s(h) - Threshold_s)}{\sum_{k=1}^{8760} Max[0, (Load_s(k) - Threshold_s)]}$$

where:

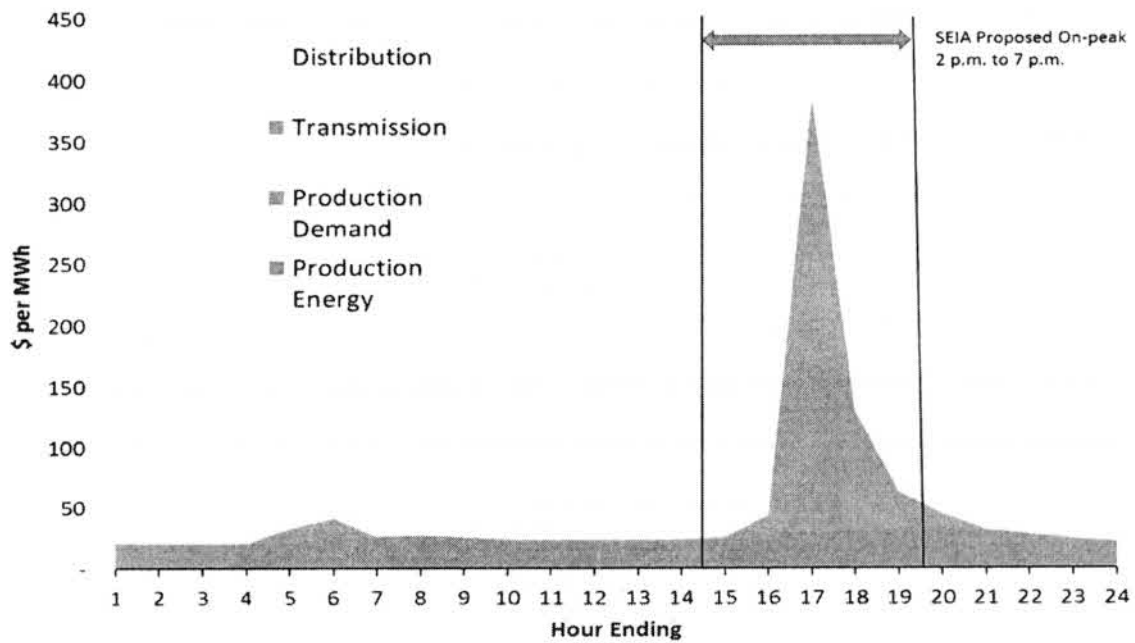
PCAF_s(h) = peak capacity allocation factor for substation *s* in hour *h*,
Load_s(h) = the load for substation *s* in hour *h*, and
Threshold_s = 90% of the substation *s* annual peak load.

Figure 3: APS Hourly Cost Profile: May-October



1

Figure 4: APS Hourly Cost Profile: November-April



2

1 Figures 3 and 4 show that the hours of 3 p.m. to 6 p.m. are critical hours in terms of
2 APS's capacity related costs for generation, transmission, and distribution, based on
3 APS's LOLPs and the peak loads on its transmission and distribution systems. These are
4 also the hours of the steepest anticipated up ramps in APS's net loads, when the utility
5 must have adequate flexible capacity to meet the new operational challenge of the "duck
6 curve."⁶⁰ The figures show that SEIA's proposed 2 p.m. to 7 p.m. on-peak period is a
7 good fit for the hourly profile of costs on the APS system. Finally, gradualism favors a
8 two-hour change in the start of the on-peak period, rather than the more significant
9 change from a noon – 7 p.m. on-peak to APS's proposed 3 p.m. to 8 p.m.
10

11 V. FIXED CHARGES
12

13 **Q67: APS has proposed to increase the residential fixed charge for R1 and R3 customers**
14 **to \$24 per month, from the current \$17 per month for TOU customers. How has**
15 **APS justified this significant increase?**

16 A67: APS proposes to add to the monthly fixed charge a share of certain costs for grid
17 operations, as well as a portion of the costs for the final line transformers on the
18 distribution system.⁶¹ The utility claims that these costs are unrelated to customers' use
19 of electricity.
20

21 **Q68: Does SEIA oppose such a large increase in the monthly fixed charge?**

22 A68: Yes. With respect to the costs for grid operations, APS has not demonstrated that these
23 costs are driven only or even principally by the number of customers on its system. Grid
24 operations costs are a function of the overall size and complexity of the utility's system,
25 which can be measured by the kWh of energy use and the kW demand for capacity as
26 well as by the number of customers. APS has long collected these costs through usage-
27 based charges, and should continue to do so.
28

⁶⁰ See, for example, APS Direct Testimony (Wilde), at Figure 1.

⁶¹ APS Direct Testimony (Meissner), at pp. 31-32.

1 With respect to the costs for final line transformers, these transformers can be used to
2 serve a variable number of small customers, depending on the customers' size. APS
3 serves an average of 5 customers from each final line transformer, but this number ranges
4 from 1 to 31 customers, depending on the size of the customer.⁶² Thus, these costs are
5 not entirely fixed, but depend on customers' demand, and should not be recovered
6 through the monthly fixed charge.

7
8 VI. THE IMPACTS OF APS'S RATE DESIGN PROPOSALS ON THE SOLAR MARKET.

9
10 A. Impacts of APS's Proposal on Solar Bill Savings

11
12 **Q69: Have you calculated the impacts of the APS R3 rate on the bill savings that would be**
13 **available to prospective solar customers, compared to APS's current rate designs,**
14 **such as the ET-2 TOU rate?**

15 A69: Yes, I have. **Table 8** below shows the reductions in bill savings from serving on-site load
16 for a variety of scenarios, including the APS R3 rate, compared to the initial base case of
17 the current APS ET-2 rate. I show the bill savings from serving the customer's on-site
18 load ("the solar offset"), because those are the savings that are impacted by retail rate
19 design. All of the bill savings in Table 8 are calculated based on the full APS census of
20 solar customers in 2015. The scenarios are:

- 21 1. **Base case of the current solar offset** under today's ET-2 two-part TOU rate.
22
23 2. **SEIA's recommendation.** The Commission should allow solar customers to
24 continue to take service under the two-part TOU rate shown in Table 6 above, a
25 rate similar to the ET-2 rate. This scenario is based on APS's proposed revenue
26 requirement and SEIA's recommended 2 p.m. to 7 p.m. on-peak period.
27
28 3. **Later on-peak period.** This case is based on SEIA's version of the ET-2 rate,
29 APS's proposed revenue requirement, and a later 3 p.m. to 8 p.m. on-peak period.
30
31 4. **APS's recommendation.** The final case shows the bill savings under APS's
32 recommended R3 rate and 3 p.m. to 8 p.m. on-peak period.
33 //

⁶² See APS response to SEIA DR 4.1.

Table 8: Solar Bill Savings from Serving On-site Load, under Various Rate Scenarios

Scenario	Rate	Type	Details of Scenario	Solar Bill Savings for Onsite Load	
				Cents/kWh	Change from #1
1	ET-2	2-part TOU	Base. Current rates, Noon-7p peak	14.2	--
3	ET-2	2-part TOU	SEIA: APS proposed GRC rates, 2p-7p peak	13.6	-4%
4	ET-2	2-part TOU	APS proposed GRC rates, 3p-8p peak	12.2	-14%
6	R3	3-part TOU	APS: APS proposed GRC rates, 3p-8p peak	8.0	-43%

Table 8 does not include reductions in bill savings due to Decision 75859's lowering of export rates. That order provides for additional reductions in the export rate in subsequent years of up to 10% per year.

B. The Cautionary Tales of SRP and NV Energy

Q70: Have any U.S. electric utilities required residential customers to use three-part rates with significant demand charges if they install DG?

A70: Yes, and the result is instructive. In early 2015, the Salt River Project (SRP) established a new Standard Electric Price Plan under which all new customers deploying customer-sited solar systems are required to take service using a new E-27 tariff. Although officially adopted by the SRP board in February 2015,⁶³ the new tariff applied retroactively to all solar customers that applied to deploy rooftop solar after December 8, 2014. Under this tariff, solar customers are subject to a range of fees that, but for the decision to install solar, would not otherwise apply, including significantly higher monthly fixed charges, as well as demand charges based on the maximum 30-minute demand in the month. Additionally, as compared to the default residential tariff that the new rate plan replaced, solar customers receive significantly lower bill credits for any excess energy sent back to the grid. SRP remains today the only utility in the U.S. with a

⁶³ As a publicly-owned utility, SRP is not regulated by the Commission.

significant number of residential solar customers that has implemented a mandatory demand charge-based rate for solar customers.

Table 9 compares SRP's current rate structure for DG customers to APS's proposed R3 rate that solar customers would be required to use. SRP has a higher monthly charge; APS has a higher winter demand charge and somewhat higher volumetric rates.

Table 9: SRP E-27 (3-10 kW) and APS's Proposed R3 Rate for DG Customers

Utility	Rate	Months	Monthly Charge \$/Month	On-Peak Energy \$/kWh	Off-Peak Energy \$/kWh	Summer On-Peak Demand \$/kW	All hours Demand \$/kW
SRP	E-27	Summer Peak (Jul-Aug)	30.94	0.0633	0.0423	17.52	NA
		Summer (May-Jun/Sep-Oct)	30.94	0.0486	0.0371	14.63	NA
		Winter (Nov-Apr)	32.44	0.0430	0.0390	NA	5.46
		Imports / Exports	Monthly Charge \$/Month	On-Peak Energy \$/kWh	Off-Peak Energy \$/kWh	Summer On-Peak Demand \$/kW	Winter On-peak Demand \$/kW
APS	R3	Summer Import rate	24.00	0.09090	0.06670	16.40	11.50
		Winter Import rate		0.05475	0.05475		
		Export rate		0.115 ^a			

^a As filed by APS in its supplemental testimony.

Q71: What has been the impact of SRP's E-27 rate on SRP's solar market since the rate was adopted?

A71: The impact of the new rate structure on the solar market in SRP's service territory has been nothing short of devastating in terms of solar adoption. Applications to install solar on the SRP system declined abruptly after December 2014, indicating the profoundly adverse impacts of the new rate plan on solar economics and customer uptake.

1 Applications fell by 95% in 2015 compared to the levels reached in 2014, before
2 recovering slightly in 2016 to 81% below 2014 levels. Thus, the solar market in SRP's
3 territory has not recovered since the new SRP rates took effect.⁶⁴ Thus, the impact in
4 SRP's service territory of a three-part rate structure that is similar to what APS has
5 proposed has been a major decline in the solar market. Depending on the outcome of this
6 case, a similar result could occur in APS's service territory. The only factor in APS's
7 territory that is more favorable than in SRP is a higher export rate, although this rate may
8 decline sharply by 10% per year under the policies adopted in Decision 75859. SEIA's
9 concern with the potential impacts on the solar DG market in Arizona is heightened by
10 the impacts of the APS rate design proposal on the bill savings that customers can realize
11 from renewable DG, as discussed above and as shown in Table 8.

12
13 **Q72: Table 8 above shows the 43% reduction in onsite bill savings in APS's territory that**
14 **could occur due to APS's proposed mandatory R3 rate for solar customers. Is there**
15 **an example of another solar market in which the state regulators have reduced bill**
16 **savings by a significant amount over a short period of time?**

17 A72: Yes. In 2015, the Public Utilities Commission of Nevada (PUCN) adopted, without
18 change, a cost-of-service study from NV Energy that showed a significant cost shift from
19 non-participating ratepayers to solar DG customers. As a result, the PUCN ended NEM
20 in Nevada, increased the fixed monthly customer charge for DG customers, and reduced
21 the export rate credited to DG systems from the full retail rate (about 11 cents per kWh
22 for residential customers) to an energy-only avoided cost rate of 2.6 cents per kWh. The
23 PUCN took this action even though its order found that there were eleven components to
24 the value of DG, but that it was only able to quantify two of those components.⁶⁵ The
25 reduction in the export rate and the increased fixed charge reduced the bill savings
26 available to NEM customers in Nevada by at least 40%. Such a precipitate reduction in

⁶⁴ One vendor, Solar City, had more than half of the SRP market before the change in SRP's tariff. Solar City pulled out of the SRP market when the new tariff took effect. Obviously, given the 80% decline in applications, the void left by Solar City's departure has not been filled by the numerous other solar vendors operating in Arizona.

⁶⁵ See PUCN Order in Dockets Nos. 15-07-041 and 15-07-042 issued December 23, 2015, at pp. 66-67 and 95-96.

1 bill savings decimated the market for new solar DG systems in Nevada, and resulted in
2 more than 1,000 documented layoffs at solar companies.⁶⁶ In 2016, the PUCN has
3 reversed course, re-evaluating the benefits and costs of solar DG and subsequently
4 adopting a reopening of full retail net metering in northern Nevada.⁶⁷ In the order re-
5 instating net metering, the new chair of the PUCN wrote:

6 The landscape on these issues continues to grow. Abraham Lincoln once said that
7 'Bad promises are better broken than kept.' The PUCN's prior decisions on NEM,
8 in several respects, may be best viewed as a promise better left unkept. The
9 PUCN is free to apply a new approach.⁶⁸
10

11 VII. APS'S UTILITY-OWNED SOLAR PARTNERS PROGRAM
12

13 **Q73: APS witness Mr. Bordenkircher discusses the APS Solar Partners Program**
14 **whereby APS has installed about 10 MW of solar DG on 1,600 customers' rooftops.**
15 **APS owns the solar systems, and rents the customers' rooftops for \$30 per month.**
16 **APS has used advanced inverters, installed two-way communications technology,**
17 **includes several distributed storage units, and is studying the impacts of these**
18 **installations on its distribution system.⁶⁹ Please provide SEIA's perspective on this**
19 **program.**

20 A73: SEIA welcomes the Solar Partners Program as a research project to gain knowledge on
21 the distribution system impacts of distributed solar with advanced inverter functionality
22 and storage. SEIA looks forward to APS widely and publicly disseminating the
23 knowledge gained in this program.
24

25 **Q74: Does SEIA support cost recovery for this program?**

26 A74: Yes. SEIA notes that the capital costs for this program (about \$4 per watt-DC) are higher
27 than the current reported market cost for residential solar DG (about \$3 per watt-DC).

⁶⁶ See *Prepared Direct and Rebuttal Testimonies of R. Thomas Beach on behalf of TASC*, served February 1 and 5, 2016 in PUCN Dockets Nos. 15-07-041 and 15-07-042.

⁶⁷ See <https://www.greentechmedia.com/articles/read/nevada-regulators-retore-retail-rate-net-metering-in-sierra-pacific-territo>.

⁶⁸ See PUCN Order in Dockets Nos. 16-06006 *et al.* issued December 20, 2016, at p. 39. Available at <http://pucweb1.state.nv.us/PDF/AXImages/Agendas/25-16/6801.pdf>.

⁶⁹ APS Testimony (Bodenkircher), at pp. 13-16.

1 Further, recovery of program costs through the utility rate base will result in 15% to 20%
2 higher costs than with third-party financing, due to the front-loaded cost recovery through
3 rate base and the higher utility cost of capital. Nonetheless, SEIA views the above-
4 market costs as reasonable given the public research benefits of the program, provided
5 those results are broadly and publicly disseminated.
6

7 **Q75: Is APS asking in this case to expand this program?**

8 A75: Not directly. APS is asking to merge the existing Flagstaff Community Power Project
9 into the SPP, but otherwise APS itself has not proposed to expand this program.⁷⁰

10 However, I understand APS is paying the legal fees of Conserve America, which has
11 proposed to expand the SPP program, so APS's position is not entirely clear.
12

13 **Q76: Would SEIA have concerns with an expansion of this program?**

14 A76: Yes. SEIA would be concerned that this program is discriminatory and anti-competitive,
15 compared to the treatment of customer-owned or third party-owned solar, for the
16 following reasons:

- 17 1. APS and the SPP customer have long-term pricing certainty, both in terms of
18 utility cost recovery and customer compensation. The solar savings of customer-
19 owned or third-party solar customers are subject to changes in rate design and
20 export rates.⁷¹
21
- 22 2. Unlike customer-owned or third-party solar customers, SPP customers would not
23 be placed in a separate customer class, and would have no restrictions on their
24 choice of rate designs.
25

26
27 **Q77: Does this conclude your prepared direct testimony?**

28 A77: Yes, it does.

⁷⁰ APS response to DR SEIA 2.11.

⁷¹ For example, Decision 75859, at page 156, limits solar customers to ten years of certainty in the export rate.

Attachment RTB-1
CV of R. Thomas Beach

Mr. Beach is principal consultant with the consulting firm Crossborder Energy. Crossborder Energy provides economic consulting services and strategic advice on market and regulatory issues concerning the natural gas and electric industries. The firm is based in Berkeley, California, and its practice focuses on the energy markets in California, the U.S., and Canada.

Since 1989, Mr. Beach has had an active consulting practice on policy, economic, and ratemaking issues concerning renewable energy development, the restructuring of the gas and electric industries, the addition of new natural gas pipeline and storage capacity, and a wide range of issues concerning independent power generation. From 1981 through 1989 he served at the California Public Utilities Commission, including five years as an advisor to three CPUC commissioners. While at the CPUC, he was a key advisor on the CPUC's restructuring of the natural gas industry in California, and worked extensively on the state's implementation of the Public Utilities Regulatory Policies Act of 1978.

AREAS OF EXPERTISE

- *Renewable Energy Issues:* extensive experience assisting clients with issues concerning Renewable Portfolio Standard programs, including program structure and rate impacts. He has also worked for the solar industry on rate design and net energy metering issues, on the creation of the California Solar Initiative, as well as on a wide range of solar issues in many other states.
- *Restructuring the Natural Gas and Electric Industries:* consulting and expert testimony on numerous issues involving the restructuring of the electric industry, including the 2000 - 2001 Western energy crisis.
- *Energy Markets:* studies and consultation on the dynamics of natural gas and electric markets, including the impacts of new pipeline capacity on natural gas prices and of electric restructuring on wholesale electric prices.
- *Qualifying Facility Issues:* consulting with QF clients on a broad range of issues involving independent power facilities in the Western U.S. He is one of the leading experts in California on the calculation of avoided cost prices. Other QF issues on which he has worked include complex QF contract restructurings, standby rates, greenhouse gas emission regulations, and natural gas rates for cogenerators. Crossborder Energy's QF clients include the full range of QF technologies, both fossil-fueled and renewable.
- *Pricing Policy in Regulated Industries:* consulting and expert testimony on natural gas pipeline rates and on marginal cost-based rates for natural gas and electric utilities.

EDUCATION

Mr. Beach holds a B.A. in English and physics from Dartmouth College, and an M.E. in mechanical engineering from the University of California at Berkeley.

ACADEMIC HONORS

Graduated from Dartmouth with high honors in physics and honors in English.
Chevron Fellowship, U.C. Berkeley, 1978-79

PROFESSIONAL ACCREDITATION

Registered professional engineer in the state of California.

EXPERT WITNESS TESTIMONY BEFORE THE CALIFORNIA PUBLIC UTILITIES COMMISSION

1. Prepared Direct Testimony on Behalf of **Pacific Gas & Electric Company/Pacific Gas Transmission** (I. 88-12-027 — July 15, 1989)
 - *Competitive and environmental benefits of new natural gas pipeline capacity to California.*
2.
 - a. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 10, 1989)
 - b. Prepared Rebuttal Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 30, 1989)
 - *Natural gas procurement policy; gas cost forecasting.*
3. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (R. 88-08-018 — December 7, 1989)
 - *Brokering of interstate pipeline capacity.*
4. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029 — November 1, 1990)
 - *Natural gas procurement policy; gas cost forecasting; brokerage fees.*
5. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission and the Canadian Producer Group** (I. 86-06-005 — December 21, 1990)
 - *Firm and interruptible rates for noncore natural gas users*

6. a. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — January 25, 1991)
b. Prepared Responsive Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — March 29, 1991)
 - *Brokering of interstate pipeline capacity; intrastate transportation policies.*
7. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029/Phase II — April 17, 1991)
 - *Natural gas brokerage and transport fees.*
8. Prepared Direct Testimony on Behalf of **LUZ Partnership Management** (A. 91-01-027 — July 15, 1991)
 - *Natural gas parity rates for cogenerators and solar thermal power plants.*
9. Prepared Joint Testimony of R. Thomas Beach and Dr. Robert B. Weisenmiller on Behalf of the **California Cogeneration Council** (I. 89-07-004 — July 15, 1991)
 - *Avoided cost pricing; use of published natural gas price indices to set avoided cost prices for qualifying facilities.*
10. a. Prepared Direct Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-033 — October 28, 1991)
b. Prepared Rebuttal Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-0033 — November 26, 1991)
 - *Natural gas pipeline rate design; cost/benefit analysis of rolled-in rates.*
11. Prepared Direct Testimony on Behalf of the **Independent Petroleum Association of Canada** (A. 91-04-003 — January 17, 1992)
 - *Natural gas procurement policy; prudence of past gas purchases.*
12. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (I. 86-06-005/Phase II — June 18, 1992)
b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council** (I. 86-06-005/Phase II — July 2, 1992)
 - *Long-Run Marginal Cost (LRMC) rate design for natural gas utilities.*
13. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 92-10-017 — February 19, 1993)
 - *Performance-based ratemaking for electric utilities.*

14. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-02-014/A. 93-03-053 — May 21, 1993)
 - *Natural gas transportation service for wholesale customers.*
15. a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — June 28, 1993)
b. Prepared Rebuttal Testimony of Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — July 8, 1993)
 - *Natural gas pipeline rate design issues.*
16. a. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — November 10, 1993)
b. Prepared Rebuttal Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — January 10, 1994)
 - *Utility overcharges for natural gas service; cogeneration parity issues.*
17. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 93-09-006/A. 93-08-022/A. 93-09-048 — June 17, 1994)
 - *Natural gas rate design for wholesale customers; retail competition issues.*
18. Prepared Direct Testimony of R. Thomas Beach on Behalf of the **SEGS Projects** (A. 94-01-021 — August 5, 1994)
 - *Natural gas rate design issues; rate parity for solar thermal power plants.*
19. Prepared Direct Testimony on Transition Cost Issues on Behalf of **Watson Cogeneration Company** (R. 94-04-031/I. 94-04-032 — December 5, 1994)
 - *Policy issues concerning the calculation, allocation, and recovery of transition costs associated with electric industry restructuring.*
20. Prepared Direct Testimony on Nuclear Cost Recovery Issues on Behalf of the **California Cogeneration Council** (A. 93-12-025/I. 94-02-002 — February 14, 1995)
 - *Recovery of above-market nuclear plant costs under electric restructuring.*
21. Prepared Direct Testimony on Behalf of the **Sacramento Municipal Utility District** (A. 94-11-015 — June 16, 1995)
 - *Natural gas rate design; unbundled mainline transportation rates.*

22. Prepared Direct Testimony on Behalf of **Watson Cogeneration Company** (A. 95-05-049 — September 11, 1995)
 - *Incremental Energy Rates; air quality compliance costs.*
23. a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — January 30, 1996)
b. Prepared Rebuttal Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — February 28, 1996)
 - *Natural gas market dynamics; gas pipeline rate design.*
24. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 96-03-031 — July 12, 1996)
 - *Natural gas rate design: parity rates for cogenerators.*
25. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 96-10-038 — August 6, 1997)
 - *Impacts of a major utility merger on competition in natural gas and electric markets.*
26. a. Prepared Direct Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — December 18, 1997)
b. Prepared Rebuttal Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — January 9, 1998)
 - *Natural gas rate design for gas-fired electric generators.*
27. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 97-03-015 — January 16, 1998)
 - *Natural gas service to Baja, California, Mexico.*

28.
 - a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 98-10-012/A. 98-10-031/A. 98-07-005 — March 4, 1999).
 - b. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — March 15, 1999).
 - c. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — June 25, 1999).
 - *Natural gas cost allocation and rate design for gas-fired electric generators.*
29.
 - a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — February 11, 2000).
 - b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — March 6, 2000).
 - c. Prepared Direct Testimony on Line Loss Issues of behalf of the **California Cogeneration Council** (R. 99-11-022 — April 28, 2000).
 - d. Supplemental Direct Testimony in Response to ALJ Cooke's Request on behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — April 28, 2000).
 - e. Prepared Rebuttal Testimony on Line Loss Issues on behalf of the **California Cogeneration Council** (R. 99-11-022 — May 8, 2000).
 - *Market-based, avoided cost pricing for the electric output of gas-fired cogeneration facilities in the California market; electric line losses.*
30.
 - a. Direct Testimony on behalf of the **Indicated Electric Generators** in Support of the Comprehensive Gas Oil Settlement Agreement for Southern California Gas Company and San Diego Gas & Electric Company (I. 99-07-003 — May 5, 2000).
 - b. Rebuttal Testimony in Support of the Comprehensive Settlement Agreement on behalf of the **Indicated Electric Generators** (I. 99-07-003 — May 19, 2000).
 - *Testimony in support of a comprehensive restructuring of natural gas rates and services on the Southern California Gas Company system. Natural gas cost allocation and rate design for gas-fired electric generators.*
31.
 - a. Prepared Direct Testimony on the Cogeneration Gas Allowance on behalf of the **California Cogeneration Council** (A. 00-04-002 — September 1, 2000).
 - b. Prepared Direct Testimony on behalf of **Southern Energy California** (A. 00-04-002 — September 1, 2000).
 - *Natural gas cost allocation and rate design for gas-fired electric generators.*

32.
 - a. Prepared Direct Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — September 18, 2000).
 - b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — October 6, 2000).
 - *Rate design for a natural gas "peaking service."*
33.
 - a. Prepared Direct Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—April 25, 2001).
 - b. Prepared Rebuttal Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—May 15, 2001).
 - *Terms and conditions of natural gas service to electric generators; gas curtailment policies.*
34.
 - a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 7, 2001).
 - b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 30, 2001).
 - *Avoided cost pricing for alternative energy producers in California.*
35.
 - a. Prepared Direct Testimony of R. Thomas Beach in Support of the Application of **Wild Goose Storage Inc.** (A. 01-06-029—June 18, 2001).
 - b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Wild Goose Storage** (A. 01-06-029—November 2, 2001)
 - *Consumer benefits from expanded natural gas storage capacity in California.*
36. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (I. 01-06-047—December 14, 2001)
 - *Reasonableness review of a natural gas utility's procurement practices and storage operations.*
37.
 - a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
 - b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
 - *Electric procurement policies for California's electric utilities in the aftermath of the California energy crisis.*

38. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association** (R. 02-01-011—June 6, 2002)
 - *"Exit fees" for direct access customers in California.*
39. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (A. 02-02-012 — August 5, 2002)
 - *General rate case issues for a natural gas utility; reasonableness review of a natural gas utility's procurement practices.*
40. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association** (A. 98-07-003 — February 7, 2003)
 - *Recovery of past utility procurement costs from direct access customers.*
41.
 - a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — February 28, 2003)
 - b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — March 24, 2003)
 - *Rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord II).*
42.
 - a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — March 21, 2003)
 - b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — April 4, 2003)
 - *Cost allocation of above-market interstate pipeline costs for the California natural gas utilities.*
43. Prepared Direct Testimony of R. Thomas Beach and Nancy Rader on behalf of the **California Wind Energy Association** (R. 01-10-024 — April 1, 2003)
 - *Design and implementation of a Renewable Portfolio Standard in California.*

44.
 - a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 23, 2003)
 - b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 29, 2003)
 - *Power procurement policies for electric utilities in California.*
45. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Indicated Commercial Parties** (02-05-004 — August 29, 2003)
 - *Electric revenue allocation and rate design for commercial customers in southern California.*
46.
 - a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 16, 2004)
 - b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 26, 2004)
 - *Policy and rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord III).*
47. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 04-04-003 — August 6, 2004)
 - *Policy and contract issues concerning cogeneration QFs in California.*
48.
 - a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 11, 2005)
 - b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 28, 2005)
 - *Natural gas cost allocation and rate design for large transportation customers in northern California.*
49.
 - a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — March 7, 2005)
 - b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — April 26, 2005)
 - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

50. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Solar Energy Industries Association** (R. 04-03-017 — April 28, 2005)
 - *Cost-effectiveness of the Million Solar Roofs Program.*
51. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration Company, the Indicated Producers, and the California Manufacturing and Technology Association** (A. 04-12-004 — July 29, 2005)
 - *Natural gas rate design policy; integration of gas utility systems.*
52.
 - a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — August 31, 2005)
 - b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — October 28, 2005)
 - *Avoided cost rates and contracting policies for QFs in California*
53.
 - a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — January 20, 2006)
 - b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — February 24, 2006)
 - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in southern California.*
54.
 - a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 — January 30, 2006)
 - b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 — February 21, 2006)
 - *Transportation and balancing issues concerning California gas production.*
55. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 06-03-005 — October 27, 2006)
 - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*
56. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 05-12-030 — March 29, 2006)
 - *Review and approval of a new contract with a gas-fired cogeneration project.*

57.
 - a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 14, 2006)
 - b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 31, 2006)
 - *Restructuring of the natural gas system in southern California to include firm capacity rights; unbundling of natural gas services; risk/reward issues for natural gas utilities.*
58. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 06-02-013 — March 2, 2007)
 - *Utility procurement policies concerning gas-fired cogeneration facilities.*
59.
 - a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — August 10, 2007)
 - b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — September 24, 2007)
 - *Electric rate design issues that impact customers installing solar photovoltaic systems.*
60.
 - a. Prepared Direct Testimony of R. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — May 15, 2008)
 - b. Prepared Rebuttal Testimony of R. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — June 13, 2008)
 - *Utility subscription to new natural gas pipeline capacity serving California.*
61.
 - a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — September 12, 2008)
 - b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — October 3, 2008)
 - *Issues concerning the design of a utility-sponsored program to install 500 MW of utility- and independently-owned solar photovoltaic systems.*

62. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-002 — October 31, 2008)
 - *Electric rate design issues that impact customers installing solar photovoltaic systems.*
63.
 - a. Phase II Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — December 23, 2008)
 - b. Phase II Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — January 27, 2009)
 - *Natural gas cost allocation and rate design issues for large customers.*
64.
 - a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 09-05-026 — November 4, 2009)
 - *Natural gas cost allocation and rate design issues for large customers.*
65.
 - a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 5, 2010)
 - b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 26, 2010)
 - *Revisions to a program of firm backbone capacity rights on natural gas pipelines.*
66. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 10-03-014 — October 6, 2010)
 - *Electric rate design issues that impact customers installing solar photovoltaic systems.*
67. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Indicated Settling Parties** (A. 09-09-013 — October 11, 2010)
 - *Testimony on proposed modifications to a broad-based settlement of rate-related issues on the Pacific Gas & Electric natural gas pipeline system.*

68.
 - a. Supplemental Prepared Direct Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 6, 2010)
 - b. Supplemental Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 13, 2010)
 - c. Supplemental Prepared Reply Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 20, 2010)
 - *Local reliability benefits of a new natural gas storage facility.*
69. Prepared Direct Testimony of R. Thomas Beach on behalf of **The Vote Solar Initiative** (A. 10-11-015—June 1, 2011)
 - *Distributed generation policies; utility distribution planning.*
70. Prepared Reply Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 10-03-014—August 5, 2011)
 - *Electric rate design for commercial & industrial solar customers.*
71. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 11-06-007—February 6, 2012)
 - *Electric rate design for solar customers; marginal costs.*
72.
 - a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Northern California Indicated Producers** (R.11-02-019—January 31, 2012)
 - b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Northern California Indicated Producers** (R. 11-02-019—February 28, 2012)
 - *Natural gas pipeline safety policies and costs*
73. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 11-10-002—June 12, 2012)
 - *Electric rate design for solar customers; marginal costs.*
74. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers and Watson Cogeneration Company** (A. 11-11-002—June 19, 2012)
 - *Natural gas pipeline safety policies and costs*

75.
 - a. Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 12-03-014—June 25, 2012)
 - b. Reply Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 12-03-014—July 23, 2012)
 - *Ability of combined heat and power resources to serve local reliability needs in southern California.*
76.
 - a. Prepared Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers and Watson Cogeneration Company** (A. 11-11-002, Phase 2—November 16, 2012)
 - b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers and Watson Cogeneration Company** (A. 11-11-002, Phase 2—December 14, 2012)
 - *Allocation and recovery of natural gas pipeline safety costs.*
77. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 12-12-002—May 10, 2013)
 - *Electric rate design for commercial & industrial solar customers; marginal costs.*
78. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 13-04-012—December 13, 2013)
 - *Electric rate design for commercial & industrial solar customers; marginal costs.*
79. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 13-12-015—June 30, 2014)
 - *Electric rate design for commercial & industrial solar customers; residential time-of-use rate design issues.*

80.
 - a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the Indicated Shippers** (A. 13-12-012—August 11, 2014)
 - b. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest, and the City of Palo Alto** (A. 13-12-012—August 11, 2014)
 - c. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation** (A. 13-12-012—September 15, 2014)
 - d. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest, and the City of Palo Alto** (A. 13-12-012—September 15, 2014)
 - *Rate design, cost allocation, and revenue requirement issues for the gas transmission system of a major natural gas utility.*
81. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (R. 12-06-013—September 15, 2014)
 - *Comprehensive review of policies for rate design for residential electric customers in California.*
82. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 14-06-014—March 13, 2015)
 - *Electric rate design for commercial & industrial solar customers; marginal costs.*
83.
 - a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A.14-11-014—May 1, 2015)
 - b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 14-11-014—May 26, 2015)
 - *Time-of-use periods for residential TOU rates.*
84. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Joint Solar Parties** (R. 14-07-002—September 30, 2015)
 - *Electric rate design issues concerning proposals for the net energy metering successor tariff in California.*
85. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 15-04-012—July 5, 2016)
 - *Selection of Time-of-Use periods, and rate design issues for solar customers.*

EXPERT WITNESS TESTIMONY BEFORE THE ARIZONA CORPORATION COMMISSION

1. Prepared Direct, Rebuttal, and Supplemental Testimony of R. Thomas Beach on behalf of **The Alliance for Solar Choice (TASC)**, (Docket No. E-00000J-14-0023, February 27, April 7, and June 22, 2016).
 - *Development of a benefit-cost methodology for distributed, net metered solar resources in Arizona.*
2. Prepared Surrebuttal and Responsive Testimony of R. Thomas Beach on behalf of the **Energy Freedom Coalition of America** (Docket No. E-01933A-15-0239 – March 10 and September 15, 2016).
 - *Critique of a utility-owned solar program; comments on a fixed rate credit to replace net energy metering.*

EXPERT WITNESS TESTIMONY BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION

1. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the **Colorado Solar Energy Industries Association** and the **Solar Alliance**, (Docket No. 09AL-299E – October 2, 2009).
https://www.dora.state.co.us/pls/efi/DDMS_Public.Display_Document?p_section=PUC&p_source=EFI_PRIVATE&p_doc_id=3470190&p_doc_key=0CD8F7FCDB673F1043928849D9D8CAB1&p_handle_not_found=Y
 - *Electric rate design policies to encourage the use of distributed solar generation.*
2. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the **Vote Solar Initiative** and the **Interstate Renewable Energy Council**, (Docket No. 11A-418E – September 21, 2011).
 - *Development of a community solar program for Xcel Energy.*
3. Answer Testimony and Exhibits, plus Opening Testimony on Settlement, of R. Thomas Beach on behalf of the **Solar Energy Industries Association**, (Docket No. 16AL-0048E [Phase II] – June 6 and September 2, 2016).
 - *Rate design issues related to residential customers and solar distributed generation in a Public Service of Colorado general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

1. Direct Testimony of R. Thomas Beach on behalf of **Georgia Interfaith Power & Light and Southface Energy Institute, Inc.** (Docket No. 40161 – May 3, 2016).
 - *Development of a cost-effectiveness methodology for solar resources in Georgia.*

EXPERT WITNESS TESTIMONY BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

1. Direct Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League** (Case No. IPC-E-12-27—May 10, 2013)
 - *Costs and benefits of net energy metering in Idaho.*
2.
 - a. Direct Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — April 23, 2015)
 - b. Rebuttal Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — May 14, 2015)
 - *Issues concerning the term of PURPA contracts in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE MASSACHUSETTS DEPARTMENT OF PUBLIC UTILITIES

1. Direct and Rebuttal Testimony of R. Thomas Beach on behalf of **Northeast Clean Energy Council, Inc.** (Docket D.P.U. 15-155, March 18 and April 28, 2016)
 - *Residential rate design and access fee proposals related to distributed generation in a National Grid general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

1. Direct and Rebuttal Testimony of R. Thomas Beach on Behalf of **Geronimo Energy, LLC**. (In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process [OAH Docket No. 8-2500-30760, MPUC Docket No. E002/CN-12-1240, September 27 and October 18, 2013])
 - *Testimony in support of a competitive bid from a distributed solar project in an all-source solicitation for generating capacity.*

EXPERT WITNESS TESTIMONY BEFORE THE MONTANA PUBLIC SERVICE COMMISSION

1. Pre-filed Direct and Supplemental Testimony of R. Thomas Beach on Behalf of **Vote Solar and the Montana Environmental Information Center** (Docket No. D2016.5.39, October 14 and November 9, 2016).
 - *Avoided cost pricing issues for solar QFs in Montana.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

1. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 97-2001—May 28, 1997)
 - *Avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*
2. Pre-filed Direct Testimony on Behalf of **Nevada Sun-Peak Limited Partnership** (Docket No. 97-6008—September 5, 1997)
 - *QF pricing issues in Nevada.*
3. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 98-2002 — June 18, 1998)
 - *Market-based, avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*
4.
 - a. Prepared Direct Testimony of R. Thomas Beach on behalf of **The Alliance for Solar Choice (TASC)**, (Docket Nos. 15-07041 and 15-07042 –October 27, 2015).
 - b. Prepared Direct Testimony of R. Thomas Beach on Grandfathering Issues on behalf of **TASC**, (Docket Nos. 15-07041 and 15-07042 –February 1, 2016).
 - c. Prepared Rebuttal Testimony of R. Thomas Beach on Grandfathering Issues on behalf of **TASC**, (Docket Nos. 15-07041 and 15-07042 –February 5, 2016).
 - *Net energy metering and rate design issues in Nevada.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

1. Prepared Direct and Rebuttal Testimony of R. Thomas Beach on behalf of **The Alliance for Solar Choice (TASC)**, (Docket No. DE 16-576, October 24 and December 21, 2016).
 - *Net energy metering and rate design issues in New Hampshire.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

1. Direct Testimony of R. Thomas Beach on Behalf of the **Interstate Renewable Energy Council** (Case No. 10-00086-UT—February 28, 2011)
<http://164.64.85.108/infodocs/2011/3/PRS20156810DOC.PDF>
 - *Testimony on proposed standby rates for new distributed generation projects; cost-effectiveness of DG in New Mexico.*

2. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the **New Mexico Independent Power Producers** (Case No. 11-00265-UT, October 3, 2011)

- *Cost cap for the Renewable Portfolio Standard program in New Mexico*

EXPERT WITNESS TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

1. Direct, Response, and Rebuttal Testimony of R. Thomas Beach on Behalf of the North Carolina Sustainable Energy Association. (In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014; Docket E-100 Sub 140; April 25, May 30, and June 20, 2014)

- *Testimony on avoided cost issues related to solar and renewable qualifying facilities in North Carolina.*

April 25, 2014:

<http://starwl.ncuc.net/NCUC/ViewFile.aspx?Id=89f3b50f-17cb-4218-87bd-c743e1238bc1>

May 30, 2014:

<http://starwl.ncuc.net/NCUC/ViewFile.aspx?Id=19e0b58d-a7f6-4d0d-9f4a-08260e561443>

June 20, 2104:

<http://starwl.ncuc.net/NCUC/ViewFile.aspx?Id=bd549755-d1b8-4c9b-b4a1-fc6e0bd2f9a2>

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OREGON

1.
 - a. Direct Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — August 3, 2004)
 - b. Surrebuttal Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — October 14, 2004)
 2.
 - a. Direct Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — February 27, 2006)
 - b. Rebuttal Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — April 7, 2006)
- *Policies to promote the development of cogeneration and other qualifying facilities in Oregon.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

1. Direct Testimony and Exhibits of R. Thomas Beach on behalf of **The Alliance for Solar Choice** (Docket No. 2014-246-E – December 11, 2014)
<https://dms.psc.sc.gov/attachments/matter/B7BACF7A-155D-141F-236BC437749BEF85>

- *Methodology for evaluating the cost-effectiveness of net energy metering*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF TEXAS

1. Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association (SEIA)** (Docket No. 44941 – December 11, 2015)

- *Rate design issues concerning net metering and renewable distributed generation in an El Paso Electric general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

1. Direct Testimony of R. Thomas Beach on behalf of the **Sierra Club** (Docket No. 15-035-53—September 15, 2015)

- *Issues concerning the term of PURPA contracts in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE VERMONT PUBLIC SERVICE BOARD

1. Pre-filed Testimony of R. Thomas Beach and Patrick McGuire on Behalf of **Allco Renewable Energy Limited** (Docket No. 8010 — September 26, 2014)

- *Avoided cost pricing issues in Vermont*

EXPERT WITNESS TESTIMONY BEFORE THE VIRGINIA CORPORATION COMMISSION

Direct Testimony and Exhibits of R. Thomas Beach on Behalf of the Maryland – District of Columbia – Virginia Solar Energy Industries Association, (Case No. PUE-2011-00088, October 11, 2011) <http://www.scc.virginia.gov/docketsearch/DOCS/2gx%2501!.PDF>

- *Cost-effectiveness of, and standby rates for, net-metered solar customers.*

LITIGATION EXPERIENCE

Mr. Beach has been retained as an expert in a variety of civil litigation matters. His work has included the preparation of reports on the following topics:

- The calculation of damages in disputes over the pricing terms of natural gas sales contracts (2 separate cases).
- The valuation of a contract for the purchase of power produced from wind generators.
- The compliance of cogeneration facilities with the policies and regulations applicable to Qualifying Facilities (QFs) under PURPA in California.
- Audit reports on the obligations of buyers and sellers under direct access electric contracts in the California market (2 separate cases).
- The valuation of interstate pipeline capacity contracts (3 separate cases).

In several of these matters, Mr. Beach was deposed by opposing counsel. Mr. Beach has also testified at trial in the bankruptcy of a major U.S. energy company, and has been retained as a consultant in anti-trust litigation concerning the California natural gas market in the period prior to and during the 2000-2001 California energy crisis.

Attachment RTB-2

Recent Cases Related to Residential Demand Charges

Attachment RTB-2: Recent Utility Proposals for Residential Demand Charges or Proto-Demand Charges

State / Utility	Docket	Utility Proposal	Outcome
<p>California Residential Rate Design Rulemaking</p> <ul style="list-style-type: none"> • PG&E • SCE • SDG&E 	CPUC R. 12-06-013	SDG&E proposed an optional rate with a schedule of increasing fixed monthly charges differentiated by the customer's maximum demand in the prior month.	CPUC Decision 15-07-001 rejected the SDG&E proposal for a demand-differentiated fixed monthly charge, finding that such a rate design was not aligned with the Commission's central focus on expanding the use of TOU rates. See D. 15-07-001, pp. 182-184 and Finding of Fact 160.
<p>California Net Metering Successor Tariff (NEM 2.0) Rulemaking</p> <ul style="list-style-type: none"> • PG&E • SCE • SDG&E 	CPUC R. 14-07-002	PG&E and SDG&E proposed non-coincident demand charges for NEM 2.0 customers.	CPUC Decision 16-01-044 rejected these PG&E and SDG&E demand charge proposals, finding that "demand charges can be complex and hard for residential customers to understand" (p. 75). The order instead requires NEM 2.0 customers in California to take service under any available TOU rate, and removes certain public benefit charges from NEM export rates. The order found that "[r]equiring participation in available TOU rates can be an effective way to align the incentives of customers on the NEM successor tariff with system needs" (p. 75).
Nevada - NV Energy 2015 NEM case	PUCN Dockets 15-07041 and 15-07042	NV Energy proposed that NEM customers should be in a separate customer class with a three-part rate design that includes a non-coincident demand charge.	PUCN order dated December 23, 2015 rejected the proposed demand charge for NEM customers finding that "ratepayer acceptance of this potential rate change is unknown" (p. 91).

Attachment RTB-2

Texas - El Paso Electric 2015 – 2016 GRC	Texas PUC Docket No. 44941	EPE proposed a separate partial requirements class for DG customers, with a non-coincident demand charge to cover distribution costs.	Case resolved by settlements. EPE dropped its proposed partial requirements class and proposed distribution demand charge for DG customers. The EPE GRC settlements were approved by the Texas PUC in an order dated August 25, 2016.
Massachusetts - National Grid 2015 GRC	MA DPU Docket 15- 155	National Grid proposed a proto-demand charge in the form of a tiered monthly customer charge. The charge would have been based on the customer's maximum monthly kWh usage over the past twelve months, and would have covered customer costs and a portion of demand-related distribution costs.	National Grid's proposed tiered customer charge was rejected by the MA DPU in an order dated September 30, 2016 (see pp. 457-462). The MA DPU found that such a rate design element did not meet its goals for either simplicity or efficiency.
Colorado - Public Service of Colorado (Xcel Energy) 2016 GRC Phase II	CoPUC Docket No. 16AL-0048E (Phase II)	PSCo proposed a proto-demand charge, the Grid Use Charge, for all residential customers. This would have been a tiered monthly customer charge covering distribution costs and based on the customer's kWh usage in the prior year.	Case resolved by settlements. In settlement, PSCo dropped its proposed Grid Use Charge. PSCo will be implementing optional pilot programs for both volumetric TOU and demand-based residential rates. The PSCo GRC settlements were approved by the CoPUC in an order dated November 23, 2016. (Note: A pending application for rehearing addresses an unrelated matter).

Attachment RTB-3

Selected Discovery Responses from APS

SOLAR ENERGY INDUSTRY ASSOCIATION'S
THIRD SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-16-0036
AND
DOCKET NO. E-01345A-16-0123
JANUARY 5, 2016

SEIA 3.1: APS' confidential E-32 NEM customer data ("SEIA 1.7_E-32 NEM _ APSRC01730.csv") provides 24 hours of data per day for each customer ID that including fields labeled as "Del" (i.e. Del_1, Del_2, ..., Del_24), "Prod," "Rec," and "Site." Please provide or explain:

- a. The meaning of these labels. For example, is "Del" the delivery from APS to the customer, "Prod" the total solar production, "Rec" the solar export from the customer to APS, and "Site" the gross load of the customer?
- b. Please state the arithmetic relationships between these variables. For example, is "Del" + "Prod" - "Rec" = "Site"?
- c. Does the existence of non-zero "Prod" data indicate that APS has total solar production data for the customer?
- d. Why are there no non-zero hourly "Prod" data for E-32 NEM customers with complete 2015 (365 rows) data?
- e. For E-32 NEM customers with complete 2015 (365 rows) data, what do the hourly "Site" loads represent?
- f. Why does APS have non-zero hourly "Prod" data for some E-32 customers but not others? Please explain the extent to which APS has data on the full solar production of the solar systems installed by E-32 customers.

Response:

- a. **Del** – measured energy delivered from APS to the customer.
Rec – measured energy received by APS from the customer.
Prod – measured customer's solar production.
Site – the energy used by a customer based on the following formula:
[Delivered Load + (Solar Production– Received Energy)]
- b. See response to SEIA 3.1a.
- c. No
- d. Some production data was not available due to missing data and non-AMI production meters.
- e. See response to SEIA 3.1a.

SOLAR ENERGY INDUSTRY ASSOCIATION'S
THIRD SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-16-0036
AND
DOCKET NO. E-01345A-16-0123
JANUARY 5, 2016

- f. See response to SEIA 3.1d. APS has access to all E-32 customers' AMI production meters.

SOLAR ENERGY INDUSTRY ASSOCIATION'S
FIFTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-16-0036
AND
DOCKET NO. E-01345A-16-0123
JANUARY 24, 2017

SEIA 5.1: At page 20 of his direct testimony, Mr. Miessner describes a study of about 1,000 customers who switched in 2013 from the ET-2 two-part rate to the ECT-2 three-part rate. Has APS performed a similar study of customers who switched in the opposite direction, from the ECT-2 three-part rate to the ET-2 two-part rate, to see how that change affected those customer's energy usage and demands? If APS has performed such a study, please provide it, with the associated workpapers.

Response: No.